PSC REF#:454202

Public Service Commission of Wisconsin
RECEIVED: 12/2/2022 3:59:12 PM

Docket No. 9818-CE-100

Response-Data Request-PSC-Grant-Ex.-2

PUBLIC

ATC American Transmission Company	Final Report	Department:	Planning
		Version	0
Title: **SYSTEM IMPACT STUDY REPORT**		Issue Date:	7-8-2021

MISO DPP 2020 Cycle East (ATC) Area Study

Phase 1 Report

Prepared for MISO

PUBLIC

Submitted By:

Chengyue Guo
Consultant Transmission Planning Engineer
Jeremy Voigt, P.E.
Senior Transmission Planning Engineer
Damien Sommer, P.E.
Consultant Transmission Planning Engineer
Mike Marz, P.E.
Principal Transmission Planning Engineer
Josh Kerr
Senior Transmission Planning Engineer
Jamal Khudai
Principal Transmission Planning Engineer
Joel Berry
Consultant Transmission Planning Engineer
Randy Johanning, P.E.
Senior Transmission Planning Engineer
Alec Dam
Intern Engineer
Paul Walter, P.E.
Manager of Resource Interconnection

THIS PAGE LEFT INTENTIONALLY BLANK

Table of Contents

1.0 EXECUTIVE SUMMARY

Thirty-three (33) resource projects have requested to interconnect to the MISO transmission network in the East (ATC) Area and are included in the Definitive Planning Phase 2020 Cycle Phase 1 study (DPP 2020 Cycle Phase 1). All Generating Facilities have requested both Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

This report presents the steady-state study results of a System Impact Study (SIS) performed to evaluate the interconnection of the generator interconnection requests in the DPP 2020 Cycle Phase 1 study. No stability, short circuit or PJM affected system analysis were performed in Phase 1. The study was performed under the direction of Midcontinent Independent System Operator (MISO) by ATC and an ad hoc study group. The results for 2025 scenario are summarized below.

1.1 Project List

The DPP 2020 Cycle Phase 1 has thirty-three (33) interconnection requests with a combined nameplate rating of 4251.19 MW. The DPP 2020 Cycle Phase 1 generator interconnection requests are listed in Table 1.1-1. The one-line diagrams of the interconnection facilities are shown in Appendix C.

[redacted].

Table 1.1-1 – Generating Facilities in DPP 2020 Cycle Phase 1 East (ATC) Area

MISO Queue #	Service Type	Control Area	County, State	Point of Interconnection	Fuel Type	Inverter Model	Main Step-Up Transformer[2]	Requested MW at POI	Dispatch (MW)[1] Batteries Discharging	
									25SH	25SUM
J1497	NRIS	WEC	Jefferson, WI	Concord 138 kV	Solar	34 x 4.2 MVA TMEIC Solar Ware Ninja PVU-L0840GR 3.99MW Total MVA = 139	One 138/34.5/13.85 kV 90/120/150 MVA %Z = 9%	125	0.00	125.00
J1502	NRIS	ALTE	Juneau, WI	Briggs Road - North Madison 345 kV	Solar	74 x 3.46 MVA Power Electronics PE HEM FS3350M 3.08MW Total MVA = 256.04	One 345/34.5/13.2 kV 153/204/255 MVA %Z = 7%	225	0.00	227.92
J1508	NRIS	WPS	Marathon, WI	Stratford – McMillan 115 kV	Wind	23 x 5.1 MVA Vesta V150 4.3MW Total MVA = 117.3	One 115/34.5/13.67 kV 64/86/107 MVA %Z = 5%	98.9	98.90	15.43
J1510	NRIS	ALTE	Wood, WI	Arpin 345 kV	Solar	28 x 4.05 MVA TMEIC NINJA 5PSC840 3.71 MW Total MVA 113.4	One 345/34.5/13.8 kV 69/92/115 MVA %Z = 8.5%	100	0.00	102.99
J1512	NRIS	ALTE	Lafayette, WI	Darlington 138 kV	Wind	23 x 5.1 MVA Vesta V150 4.3MW Total MVA = 117.3	One 138/90/13.2 kV 69/92/115 MVA %Z = 3% One 90/34.5/13.2 kV 69/92/115 MVA %Z = 3%	98.9	98.90	15.43
J1513	NRIS	WEC	Waupaca, WI	Highway 22 345 kV	Solar	82 x 4.05 MVA TMEIC Ninja 5PCS840 3.71MW Total MVA = 332.1	Two 345/34.5/13.8 kV 102/136/170 MVA %Z = 8.5%	300	0.00	304.22
J1567	NRIS	WEC	Outagamie, WI	Werner West 138 kV	Solar	41 x 4.05 MVA TMEIC NINJA 5PCS840 3.71MW Total MVA = 166.05	One 138/34.5/13.8 kV 102/136/170 MVA %Z = 8.5%	150	0.00	152.00
J1573	NRIS	WPS	Portage, WI	Plover 115 kV	Solar	80 x 3.8 MVA Power Electronics FS3670K 3.61 MW Total MVA = 304 MW	Two 115/34.5/13.8 kV 95/125/155 MVA %Z = 9%	250	0.00	253.54
J1615	NRIS	WEC	Oconto, WI	Morgan 138 kV	Solar	41 x 4.05 MVA TMEIC Ninja 5PSC840 3.71MW Total MVA = 166.05	One 138/34.5/13.8 kV 120/140/170 MVA %Z = 8.5%	150	0.00	152.03
J1629	NRIS	ALTE	Columbia, WI	Columbia - South Fond Du Lac 345 kV Line	Solar	58 x 3.948 MVA SMA Sunny Central SC4200-UP 3.505MW Total MVA = 228.98	One 345/34.5/13.8 kV 134/179/223 MVA %Z = 9%	200	0.00	203.29
J1706	NRIS	ALTE	Green, WI	North Monroe 138 kV	Solar	1 x 3.15 MVA Sungrow SG3150U 2.835MW Total MVA = 113.4	One 138/34.5/13.8 kV 66/88/110 MVA %Z = 9.5%	100	0.00	101.48
J1708	NRIS	ALTE	Grant, WI	J947 Interconnection Substation 138 kV	Solar	27 x 3.15 MVA Sungrow SG3150U Total MVA = 85.05	One 138/34.5/13.8 kV 54/72/90 MVA %Z = 9.5%	75	0.00	76.06
J1716	NRIS	ALTE	Fond du Lac, WI	South Fond Du Lac to Fitzgerald 345 kV	Solar	32 x 3.55 MVA Power Electronics FS3430M 3.156MW Total MVA = 113.6	One 345/34.5/13.8 kV 144/192/240 MVA %Z = 9%	100	0.00	100.99
J1719	NRIS	ALTE	Waushara, WI	Sand Lake 138 kV	Solar	35 x 3.15 MVA Sungrow SG315OU 2.99 MW Total MVA = 104.7	One 138/34.5/13.8 66/88/110 MVA %Z = 10%	100	0.00	101.41

[redacted]

J1720	NRIS	ALTE	Columbia, WI	Fountain Prairie -North Randolph 138 kV	Solar	29 x 3.948 MVA SMA Sunny Central SC4200-UP 3.46MW Total MVA = 114.49	One 138/34.5/13.8 kV 66/88/119 MVA %Z = 9%	99	0.00	100.09
J1732	NRIS	ALTE	Columbia, WI	ACEC Lewiston -Trienda 138 kV	Solar	47 x 2.31 MVA Power Electronics HEMK FS2235K 1.999767MW Total MVA = 115.5	One 138/34.5/13.8 kV 72/96/120 MVA %Z = 10%	99.99	0.00	99.99
J1735	NRIS	ALTE	Rock, WI	J1304 Interconnection Substation 138 kV	Solar	1 x 3.15 MVA Sungrow SG3150U 2.838MW Total MVA = 85.05	One 138/34.5/13.8 kV 54/72/90 MVA %Z = 9.5%	75	0.00	76.07
J1740	NRIS	WEC	Walworth, WI	University to Mukwonago 138 kV	Solar	35 x 3.15 MVA Sungrow SG3150U 2.99MW Total MVA = 110.3	One 138/34.5/13.8 kV 66/88/110 %Z = 10%	100	0.00	101.88
J1745	NRIS	WPS	Winnebago, WI	Fitzgerald 138 kV	Solar	36 x 3.15 MVA Sungrow SG3150U 2.835MW Total MVA = 113.4	One 138/34.5/13.8 kV 66/88/110 MVA %Z = 9.5%	100	0.00	101.62
J1746	NRIS	ALTE	Columbia, WI	Columbia 138 kV	Solar	53 x 3.15 MVA Sungrow SG3150U 2.835U Total MVA = 166.95	One 138/34.5/13.8 kV 105/140/175 MVA %Z = 9.5%	150	0.00	150.26
J1750	NRIS	MIUP	Marquette, MI	Huron - Empire 138 kV	Solar	34 x 4.77 MVA TMEIC Solar Ware Ninja PVU-L0840GR 4.5MW Total MVA = 162.18	One 138/34.5/13.8 kV 107/143/178 MVA %Z = 7%	149.7	0.00	152.99
J1751	NRIS	ALTE	Wood, WI	ACEC Badger West - Saratoga 138 kV	Solar	34 x 4.77 MVA TMEIC Solar Ware Ninja PVU-L0840GR 4.5 MW Total MVA = 153	One 138/34.5/13.8 kV 107/143/178 MVA %Z = 7%	150.5	0.00	152.60
J1752	NRIS	WPS	Portage, WI	Golden Sands 138 kV	Solar	34 x 4.77 MVA TMEIC Solar Ware Ninja PVU-L0840GR 4.5 MW Total MVA = 153	One 138/34.5/13.8 kV 107/143/178 MVA %Z = 7%	148.1	0.00	152.58
J1773	NRIS	ALTE	Iowa, Lafayette, WI	Hill Valley to Cardinal 345 kV	Wind	100 x 3.367 MVA GE DFIG 3.03MW Total MVA = 336.7	Two 345/34.5/13.8 kV 100/133/167 MVA %Z=8%	300	303	47.27
J1778	NRIS	WEC	Kenosha, WI	Paris 138 kV	Solar	27 x 4.2 MVA TMEIC Solar Ware Ninja PVU-L0840GR 3.99MW Total MVA = 111	Two 138/34.5/13.8 kV 75/100/125 MVA %Z = 9%	100	0.00	100.00
J1779	NRIS	ALTE	Dane, WI	Rockdale 345 kV	Solar	53 x 4.2 MVA TMEIC Solar Ware Ninja PVU-L0840GR Total MVA = 222.6	Two 345/34.5/13.8 kV 75/100/125 MVA %Z=9%	200	0.00	200.00
J1781	NRIS	ALTE	Iowa, Lafayette, WI	Hill Valley 345 kV	Wind	100 x 3.367 MVA GE DFIG 3.03MW Total MVA = 336.7	Two 345/34.5/13.8 kV 100/133/167 MVA %Z=8%	300	303	47.27
J1793	NRIS	WEC	Sheboygan, WI	Holland 138 kV	Solar	27 x 3.15 MVA Sungrow SG3150U 2.835MW Total MVA = 85.05	One 138/34.5/13.8 kV 54/72/90 MVA %Z = 9.5%	75	0.00	76.07
J1803	NRIS	UPPCO	Houghton, MI	J1244 Interconnection Substation 69 kV	Wind	8 x 5.3 MVA Siemens/Gamesa SG 5.0MW Total MVA 42.4	Two 69/34.5/13.8 kV 15/20/25 MVA %Z = 7.5%	1.6	20.00[3]	6.24[3]
J1814	NRIS	MIUP	Dickinson, MI	Nordic 138 kV	Solar	6 x 4.0 MVA SMA Sunny Central SC4400 UP-US 3.6MW Total MVA = 24.02	One 138/34.5/13.8 kV 18/24/30 MVA %Z = 8.5%	22.5	0.00	22.87

[redacted].

J1817	NRIS	UPPCO	Houghton, MI	J1244 Interconnection Substation 69 kV	Wind	4 x 5.3 MVA Siemens Gamesa SG 5.0145 5.0MW Total MVA = 21.4	One 69/34.5/13.8 kV 15/20/25 MVA %Z = 7.5%	20	20.00	3.12
J1824	NRIS	ALTE	Columbia, WI	Academy 138 kV	Solar	36 x 2.31 MVA PE HEMK FS2235K 1.9999MW Total MVA = 86.63	One 138/34.5/13.8 kV 54/72/90 MVA %Z = 10%	75	0.00	75.00
J1843	NRIS	ALTE	Dane, WI	Christiana 138 kV	Gas	N/A	Existing	12	0	499.89[4]

[1] Per MISO BPM 015-r22 the following dispatch assumptions are applied for each Fuel Type.

a. Combined Cycle (CC) is dispatched to 50% of the Requested MW in the shoulder models, 100% in the summer peak model.
b. Solar is dispatched offline in the shoulder models, 100% in the summer peak model.
c. Wind is dispatched to 100% of the Requested MW in the shoulder models, 15.6% in the summer peak model.
d. Battery is dispatched to 100% of the Requested MW in discharging mode in the summer peak model and dispatched in both charging and discharging modes to +/-100% of the Requested MW in the shoulder models.
e. Hybrid is dispatched according to Appendix E of MISO BPM 015-r22.

[2] Three winding transformers add a node not assigned to a PSSE bus number which must be initialized for every model build. Past experience has shown that these nodes not assigned to a PSSE bus number have been a source for power flow model solution difficulties. Since the third winding, when it has no devices such as a shunt or load connected to it, has no impact on the steady-state modeling ATC has opted to not model them. The three-winding transformers will be modeled as a three-winding transformer for the short circuit study

[3] J1244 total dispatch. J1803 is a request of increasing J1244 output by 1.6 MW.

[4] Total dispatch of three Christiana CTs. J1843 is a request of increasing Christiana CTs by 12 MW. Auxiliary load was netted with the CTs,

1.2 Generating Facility Requirements

1.2.1 Voltage Schedule Requirement

ATC requires all generators in its territory to maintain a voltage schedule at the Point of Interconnection (POI). The standard voltage schedule is 1.02 per unit as measured at the POI. This schedule may be changed by the Transmission Operator for specific power plants or specific conditions.

1.2.2 Power Factor Range Requirement

FERC Order 827 and ATC Criteria require all newly interconnecting generators interconnecting to ATC-owned Facilities to provide a power factor range for synchronous and non-synchronous (e.g., wind turbines, solar) generation of 0.95 leading (when a Generating Facility is consuming reactive power from the transmission system) to 0.95 lagging (when a Generating Facility is supplying reactive power to the transmission system).

Unless physically disconnected from the ATC transmission system, the Generating Facility must be capable of maintaining ATC's standard power factor range at all power output levels by providing dynamic reactive power at the following locations:

A. The POI for all synchronous generators
B. The high-side of the generator substation for all non-synchronous generators

For synchronous generators, the interconnection studies will account for the net effect of all energy production devices and losses on the Customer's side of the POI.

- Dynamic reactive power provided by a synchronous Generating Facility may meet the dynamic reactive power requirement by utilizing a combination of the inherent dynamic reactive power capability of the synchronous generator, dynamic reactive power devices (e.g., Static VAR Compensators), and static reactive power devices (e.g., capacitors) to make up for losses.
- Dynamic leading reactive power provided by a synchronous Generating Facility cannot use inductive losses from generator step-up transformer(s) and generator tie line(s) to meet the leading power factor calculation at POI. A synchronous Generating Facility must be able to meet a 0.95 leading power factor, as measured at the generator terminal (i.e. the low side of the generator step-up transformer).

For non-synchronous generators, the interconnection studies will account for the net effect of all energy production devices and losses on the Customer's side of generator substation step-up transformer.

- Dynamic reactive power provided by a non-synchronous Generating Facility must meet the following requirement from FERC order 827 paragraph 35:
    - "Non-synchronous generators may meet the dynamic reactive power requirement by utilizing a combination of the inherent dynamic reactive

power capability of the inverter, dynamic reactive power devices (e.g., Static VAR Compensators), and static reactive power devices (e.g., capacitors) to make up for losses."

- Dynamic leading reactive power provided by a non-synchronous Generating Facility cannot use inductive losses from pad-mount and station step-up transformers and collector system to meet the leading power factor calculation at the high-side of the generator substation. A non-synchronous Generating Facility must be able to meet a leading 0.95 power factor, as measured at the generator terminal (i.e. the low side of the pad-mount transformer).
- Dynamic lagging reactive power provided by a non-synchronous Generating Facility cannot use collector system charging to meet the lagging power factor calculation at the high-side of the generator substation. A non-synchronous Generating Facility must be able to meet a lagging 0.95 power factor, as measured at the generator terminal (i.e. the low side of the pad-mount transformer).
- When the Generating Facility is not generating active power (i.e. zero MW output):
    - The reactive power injection to the transmission system at the high-side of the generator substation should be zero Mvar.
    - When the Generating Facility is physically connected but operating at zero MW and zero Mvar as measured at the high-side of the generator substation, the Generating Facility is not required to control system voltage.

Static reactive power devices (e.g., capacitors and inductors) can only be used to make up for

- Inductive losses between the generator terminal and the POI for synchronous generators, or
- Inductive losses or collector system charging between the generator terminal and the high side of generator substation for non-synchronous generators.

All other reactive power needed to meet the power factor requirement must be provided by continuous and sustainable dynamic sources. Operation across the entire power factor range must be fully dynamic, variable, and capable of sustained indefinite operation.

Static sources can be switched on or off in the range of seconds and provide reactive power in large discrete blocks. Cap Banks are considered static sources of reactive power.

Dynamic sources can provide variable amounts of reactive power in a few milliseconds. Static Var Compensators (SVCs), Static Synchronous Compensators (STATCOMs), Flexible AC Transmission Systems (FACTS), inverters, and synchronous condensers are all considered dynamic sources of reactive power.

For non-synchronous generation projects in the DPP 2020 Cycle Phase 1 study group, if they did not have a signed Generator Interconnection Agreement (GIA) [redacted].

or Provisional GIA (PGIA) by September 21, 2016, they are required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.

The generation requests shown in Table 1.2.2-1 did not meet the dynamic reactive power requirements per FERC Order 827 and ATC Criteria at the time of the model completion and are required to provide additional dynamic reactive power sources. All other requests in this queue met FERC Order 827 and ATC Criteria for dynamic reactive power requirements.

Table 1.2.2-1 – Additional Dynamic Mvar to meet ATC Dynamic Inductive Power Factor Requirement and FERC Order 827 Power Factor Requirements

MISO Queue #	Type	Additional Dynamic Reactive Compensation (Mvar)
J1508	Wind Generation	2.16
J1512	Wind Generation	2.16
J1843	Natural Gas	23.37

The generation requests shown in Table 1.2.2-2 did not meet the static reactive power requirements per ATC Criteria at the time of the model completion and are required to provide additional static reactive power sources. All other requests in this queue met FERC Order 827 and ATC Criteria for static reactive power requirements.

Table 1.2.2-2 – Additional Static Mvar to meet ATC Capacitive Power Factor and FERC Order 827 Power Factor Requirements

MISO Queue #	Type	Additional Static Shunt Compensation [1] (Mvar)
J1508	Wind Generation	4.6
J1513	Solar Generation	25.5
J1706	Solar Generation	6.4
J1708	Solar Generation	3.9
J1719	Solar Generation	13.1
J1244/J1803/J1817	Wind Generation	1.8
J1735	Solar Generation	3.9
J1740	Solar Generation	21.1
J1745	Solar Generation	6.4
J1746	Solar Generation	7.7
J1793	Solar Generation	3.9

[1] Additional compensation is required to meet the criteria at the POI Bus for synchronous Generating Facilities or the high-side of the generator substation for asynchronous Generating Facilities.

When non-synchronous Generating Facility is not generating active power (i.e. zero MW output), the reactive power injection to the transmission system at the high-side of the generator substation should be zero Mvar. Table 1.2.2-2 shows the Mvar levels expected at the high-side of the generator substations for all non-synchronous generation requests when not generating. Inductive power devices or the generating facilities inverters can be used to counter var flows created at low or no output levels.

Table 1.2.2-3 – Assessment of Reactive Power Injection to the Transmission System When Non-synchronous Generator is at zero MW output

MISO Queue #	Additional inductive Mvar required at the high-side of generator substation to meet ATC Power Factor Requirement when non-synchronous generator is at zero MW output
J1497	14.3
J1502	5.3
J1508	5.5
J1510	9.1
J1512	14.6
J1513	1.2
J1567	0.6
J1573	4.0
J1615	0.6
J1629	3.4
J1706	0.9
J1708	0.6
J1716	0.1
J1719	1.5
J1720	1.2
J1732	1.1
J1735	0.6
J1740	1.5
J1745	0.9
J1746	1.5
J1750	11.7
J1751	6.5
J1752	19.0
J1773	2.8
J1778	5.3
J1779	10.7
J1781	5.6

J1793	0.6
J1244/J1803/J1817	1.4
J1814	0.1
J1824	0.7

1.2.3 Island Detection and Operation

In circumstances where the Generating Facility has no governor controls and the transmission system design could result in an islanding condition for the outage of two transmission elements, ATC requires the Customer to implement additional protection systems as mutually agreed by the Customer and ATC to prevent generation from being isolated or islanded with interconnected load. Alternatively, ATC will require the Customer to curtail their generation for circumstances that could result in an island condition with the next contingency.

This would apply to the following Generating Facilities from this DPP cycle that lack adequate governor controls to safely and reliably sustain an island with load.

- J1508
- J1708
- J1720
- J1732
- J1735
- J1750
- J1751
- J1793

1.3 Total Network Upgrades for all Projects

The cost allocation of Network Upgrades for the study group reflects responsibilities for mitigating system impacts based on Interconnection Customer-elected level of Energy Resource Interconnection Service and Network Resource Interconnection Service as of the SIS report date. The total cost of Network Upgrades required for each generator interconnection request is listed in Table 1.3-1. The costs for Network Upgrades are planning level estimates and subject to be revised in the facility studies. No Network Upgrade projects driven by stability, short circuit and PJM affected system analysis were not identified since these analyses were not performed in Phase 1. All Interconnection Facility Project Diagrams are documented in Appendix C and all Network Upgrade Project Diagrams are documented in Appendix D (No project diagrams are developed for line uprates).

Table 1.3-1 – Total Cost of Network Upgrades for DPP 20 Cycle Phase 1 Generator Interconnection Requests

MISO Queue #	Requested MW	ERIS Network Upgrades ($) [3]				NRIS Network Upgrades ($)	Interconnection Facilities ($)		Shared Network Upgrade ($)	Total Cost of Network Upgrades (Exclude TOIF & Affected Systems) ($)	M2 Received ($)[1]	M3 Due ($)[2]
		Steady - State Thermal & Voltage	Transient Stability	Short Circuit	Affected System		TO Network Upgrades	TO-Owned Direct Assigned (TOIF) [4]				
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]=[c]+[d]+[e]+[g]+[h]	[l] = $4000 x [b]	[m]= (10%of [k])-[l]
J1497	125	0	0	0	0	38,471,632	540,589	442,000	0	39,012,221	500,000	3,401,222
J1502	225	0	0	0	0	4,541,469	10,245,000	582,000	0	14,786,469	900,000	578,647
J1508	98.9	0	0	0	0	5,606,664	7,813,000	291,000	0	13,419,664	395,600	946,366
J1510	100	0	0	0	0	5,243,029	1,305,893	554,000	0	6,548,922	400,000	254,892
J1512	98.9	11,846,981	0	0	0	5,236,866	3,976,700	261,692	0	21,060,547	395,600	1,710,455
J1513	300	0	0	0	0	16,661,198	1,459,771	571,868	0	18,120,969	1,200,000	612,097
J1567	150	0	0	0	0	8,547,866	1,469,767	304,136	0	10,017,633	600,000	401,763
J1573	250	0	0	0	0	14,371,480	971,985	410,000	0	15,343,465	1,000,000	534,347
J1615	150	0	0	0	0	8,780,296	1,710,311	601,978	0	10,490,607	600,000	449,061
J1629	200	2,405,225	0	0	0	6,684,628	11,268,000	299,000	0	20,357,853	800,000	1,235,785
J1706	100	0	0	0	0	8,946,858	908,384	619,670	0	9,855,242	400,000	585,524
J1708	75	0	0	0	0	1,504,170	1,377,857	306,000	0	2,882,026	300,000	0
J1716	100	0	0	0	0	5,835,537	0	0	0	5,835,537	400,000	183,554
J1719	100	6,606,859	0	0	0	13,150,476	4,933,354	410,000	0	24,690,689	400,000	2,069,069
J1720	99	2,963,692	0	0	0	6,535,078	7,330,000	298,000	0	16,828,770	396,000	1,286,877
J1732	99.99	0	0	0	0	2,400,232	6,978,000	284,000	0	9,378,232	399,960	537,863
J1735	75	0	0	0	0	5,991,867	663,777	619,550	0	6,655,644	300,000	365,564
J1740	100	0	0	0	0	44,217,433	7,618,000	291,000	0	51,835,433	400,000	4,783,543
J1745	100	0	0	0	0	5,842,029	418,405	750,851	0	6,260,434	400,000	226,043
J1746	150	0	0	0	0	3,587,430	867,472	353,387	0	4,454,902	600,000	0
J1750	149.7	0	0	0	0	8,621,660	7,151,000	291,000	0	15,772,660	598,800	978,466
J1751	150.5	708,146	0	0	0	10,577,336	7,151,000	291,000	0	18,436,482	602,000	1,241,648
J1752	148.1	0	0	0	0	7,763,404	6,938,397	410,000	0	14,701,801	592,400	877,780
J1773	300	11,467,880	0	0	0	3,127,936	12,311,000	597,000	0	26,906,816	1,200,000	1,490,682
J1778	100	0	0	0	0	10,335,550	0	0	0	10,335,550	400,000	633,555
J1779	200	0	0	0	0	3,084,154	0	0	0	3,084,154	800,000	0
J1781	300	4,134,080	0	0	0	2,278,847	3,394,162	852,000	0	9,807,089	1,200,000	0
J1793	75	0	0	0	0	6,116,969	1,446,544	679,763	0	7,563,513	300,000	456,351
J1803	1.6	0	0	0	0	551,901	280,121	0	0	832,022	6,400	76,802
J1814	22.5	0	0	0	0	1,294,504	359,911	712,391	0	1,654,415	90,000	75,441
J1817	20	0	0	0	0	6,811,648	280,121	0	0	7,091,769	80,000	629,177
J1824	75	2,164,051	0	0	0	7,464,470	353,698	360,138	0	9,982,219	300,000	698,222
J1843	12	1,095,926	0	0	0	9,029	0	0	0	1,104,955	48,000	62,495
Total ($)	-	43,392,838	0	0	0	280,193,648	111,522,219	12,443,424	0	435,108,706	17,004,760	27,383,293

[redacted]

[1] M2: Milestone Payment dollars received by MISO
[2] M3 = (10% of NU)-M2
[3] Transient stability, short circuit, and affected system studies will be performed as part of MISO DPP 2020 Cycle Phase 2.
[4] TOIF: Transmission Owner shall collect from Interconnection Customer a tax gross-up amount on the payments made to Transmission Owner using the Transmission Owner rate in effect at the time the payment is received from Interconnection Customer.
[5] ATC projects are estimated in ISD dollars with a 2.5% annual escalation rate and include a contingency based on a project risk generally between 5% – 20%.

[redacted].

1.4 In-Service Dates and Cost Estimates

ATC understands that the estimated in-service date may not align with the Interconnection Customer's Synchronization Date; however, negotiated and executed agreements, such as an Engineering and Procurement Agreement, can be used prior to the GIA execution date to expedite Network Upgrades. In absence of any special arrangement, typical times to develop a new Interconnection Facility is about 24-36 months after the GIA is executed, assuming no delays due to Interconnection Customer's permits, state processes, land acquisitions, deliverables (such as a finish graded substation site, etc.) It also assumes that system outages required to construct facilities can be obtained timely. The cost estimates for Interconnection Facilities are based on the in-service date provided in the Interconnection Customer's application data. Therefore, any change in in-service date will have impact on the cost estimates. The requested dates for Interconnection Facility in-service, synchronization, and commercial operation are summarized in Table 1.4-1.

Table 1.4-1 – Requested Interconnection Facilities In-Service Dates, Synchronization Dates and Commercial Operation Dates

MISO Queue #	Requested Interconnection Facility In-service Date	Requested Synchronization Date	Requested Commercial Operation Date
J1497	10/30/2024	10/01/2024	12/31/2024
J1502	03/31/2023	04/15/2023	06/30/2023
J1508	09/01/2023	09/15/2023	12/31/2023
J1510	10/01/2023	11/01/2023	12/01/2023
J1512	09/01/2023	09/15/2023	12/31/2023
J1513	10/01/2023	11/01/2023	12/01/2023
J1567	10/01/2023	11/01/2023	12/01/2023
J1573	09/01/2023	10/01/2023	12/31/2023
J1615	10/01/2023	11/01/2023	12/01/2023
J1629	07/18/2024	05/26/2024	05/01/2024
J1706	06/01/2025	09/01/2025	12/01/2025
J1708	06/01/2025	09/01/2025	12/01/2025
J1716	08/01/2022	09/01/2022	12/31/2022
J1719	09/01/2023	09/01/2023	12/31/2023
J1720	05/20/2024	05/27/2024	07/18/2024
J1732	12/31/2022	12/31/2022	12/31/2022
J1735	06/01/2025	09/01/2025	12/01/2025
J1740	09/01/2023	09/01/2023	12/31/2023
J1745	06/01/2025	09/01/2025	12/01/2025
J1746	06/01/2025	09/01/2025	12/01/2025

J1750	08/01/2023	09/01/2023	11/30/2023
J1751	08/01/2023	09/01/2023	11/30/2023
J1752	08/01/2023	09/01/2023	11/30/2023
J1773	04/15/2024	04/30/2024	12/31/2024
J1778	10/31/2024	10/01/2024	12/31/2024
J1779	10/31/2024	10/01/2024	12/31/2024
J1781	04/15/2024	04/30/2024	12/31/2024
J1793	06/01/2025	09/01/2025	12/01/2025
J1803	09/15/2021	10/05/2021	10/29/2021
J1814	09/15/2023	10/15/2023	12/15/2023
J1817	09/15/2021	10/05/2021	10/29/2021
J1824	12/31/2022	12/31/2022	12/31/2022
J1843	3/15/2023	3/31/2023	5/31/2023

1.5 MTEP Projects

If a MTEP transmission project(s) resolves the constraint, and that project(s) is approved by the Board within (1) calendar year of the GIA execution or execution of an amendment thereof, then the Interconnection Customer will not be responsible for transmission upgrade(s) that would resolve the constraint. If that MTEP project(s) is not approved within one (1) calendar year of the GIA execution or execution of an amendment thereof, the Interconnection Customer will be responsible for those transmission upgrade(s).

1.6 Further Study

The next step in the MISO Generator Interconnection Procedures is to perform additional SISs (if needed), Interconnection Customer Interconnection Facility Studies, and Network Upgrade Facility Studies. Those Facilities Studies will specify in more detail the time and cost of the equipment, engineering, procurement, and construction of the Interconnection Facilities and Network Upgrades identified in this report.

1.7 Compliance Summary

This study report partially meets NERC TPL-001-4 standard, FAC-002-2 standard, and Local Planning Criteria. In ATC's annual Ten-Year Assessment (TYA) and MISO annual MTEP studies, additional compliance related studies will be performed for the generator interconnection requests with signed GIAs. Appendix J describes in detail the NERC and Local Criteria requirements met by this SIS report.

2.0 STEADY-STATE ANALYSIS

Steady-state analysis was performed to identify thermal and voltage upgrades required to interconnect the generator interconnection requests in the DPP 2020 Cycle Phase 1 to the transmission system. Detailed study assumptions, criteria, and methodology are documented in Appendix A.

2.1 Model Development

2.1.1 Study Cases

Two study cases for the steady-state thermal and voltage analysis were developed based upon the expected topology for the local area: 2025 summer peak batteries discharging and 2025 shoulder batteries discharging. The ATC system in these cases was updated with the most recent data available at the time of model construction. The cases were reviewed by ATC and the Interconnection Customers. Based on this review, the cases were further modified to account for model updates, changes, and competing generation requests that had dropped out of the MISO queue since the models were built.

The prior queued generator interconnection requests in the ATC system that are included in the study cases are listed in Table 2.1.1-1. Associated Network Upgrades were also included.

Table 2.1.1-1 – Prior Queued Generator Interconnection Requests Not Yet In-Service

MISO Queue #	Type	Control Area	Requested MW
J505	Solar	WPS	99
J732	CC	WPS	561.5
J818	Solar	WEC	149
J849	Solar	MIUP	125
J850	Solar	ALTE	250
J855	Wind	ALTE	100
fJ864	Solar	ALTE	49.98
J870	Solar	ALTE	200
J871	Solar	ALTE	100
J878	Solar	WEC	200
J886	Solar	WPS	150
J928	Wind	MIUP	79.995
J947	Solar	ALTE	200
J986	Solar	ALTE	149.76
J1000	Solar	ALTE	50
J1002	Solar	ALTE	99
J1003	Solar	ALTE	50
J1042	Solar	ALTE	180
J1101	Battery	WPS	20
J1153	Solar	WEC	150
J1154	Solar	WEC	75
J1171	Solar	WEC	100
J1183	Solar	MIUP	1.35
J1188	Solar	ALTE	50
J1214	Solar	ALTE	300
J1244	Wind	UPPCO	38.4
J1251	Solar	MIUP	100
J1253	Solar	WPS	100

J1304	Solar	ALTE	65
J1305	Solar	ALTE	49.9
J1316	Battery	WEC	50
J1326	Battery	ALTE	75
J1345	Battery	ALTE	25
J1370	Gas	MIUP	50
J1374	Wind	ALTE	67.2
J1377	Solar	ALTE	98.56
J1410	Solar	MGE	300
J1411	Battery	MGE	75
J1460	Solar	ALTE	200
J1483	Wind	ALTE	99

Public information related to the MISO Generator Interconnection Request queue can be found at:

https://www.misoenergy.org/planning/generator-interconnect`ion/GI_Queue/

The summer peak discharging and shoulder discharging cases dispatched generation within MISO according to section 6.1.1.1.2, Study Case Development, in the MISO BPM-015-r22.

All excess generation from this methodology is dispatched against all units in MISO Classic proportionally, excluding the units in the current DPP cycle. Scheduled firm transfers are ignored in this dispatch methodology.

2.1.2 Benchmark Cases

Two benchmark cases were used to benchmark system performance without the DPP 2020 Cycle Phase 1 generating facilities and were created by taking the DPP 2020 Cycle Phase 1 Generating Facilities offline from the corresponding study cases. The MISO Classic was used for power balance, where generation was scaled in proportion to Pmax minus Pgen.

2.2 Reactive Power Requirements (FERC Order 827)

All synchronous and non-synchronous generation in this queue were evaluated to determine if the requests meet FERC Order 827 and ATC Planning Criteria. Refer to PLG-METH-0005 in Appendix B for details on ATC's power factor analysis methodology. All of the reactive resources modeled in the assessment are summarized in Table 2.2-1.

Table 2.2-1 – Reactive Resources Modeled in Generator Interconnection Power Factor Analysis

MISO Queue #	Machines				Dynamic Devices			Static Devices		
	Description	Real Power Pmax (MW)	Capacitive Reactive Power Qmax (Mvar)	Inductive Reactive Power Qmin (Mvar)	Description	Capacitive Reactive Power (Mvar)	Inductive Reactive Power (Mvar)	Description	Capacitive Reactive Power (Mvar)	Inductive Reactive Power (Mvar)
J1497	Solar Machines	125.00	60.50	-60.50	None	N/A	N/A	1 - 4 Mvar Cap	4	0
J1502	Solar Machines	227.92	116.77	-116.77	None	N/A	N/A	None	0	0
J1508	Wind Turbines	98.90	42.73	-30.35	None	N/A	N/A	None	0	0
J1510	Solar Machines	103.88	44.25	-44.25	None	N/A	N/A	2 - 10 Mvar Cap	20	0
J1512	Wind Turbines	98.90	42.73	-30.35	None	N/A	N/A	None	0	0
J1513	Solar Machines	304.22	129.60	-129.60	None	N/A	N/A	2 - 10 Mvar Cap	20	0
J1567	Solar Machines	152.11	64.80	-64.80	None	N/A	N/A	2 - 10 Mvar Cap	20	0
J1573	Solar Machines	254.6	82.00	-82.00	None	N/A	N/A	4 - 7 Mvar Cap	28	0
J1615	Solar Machines	152.11	64.80	-64.80	None	N/A	N/A	2 - 10 Mvar Cap	20	0
J1629	Solar Machines	203.29	104.15	-104.15	None	N/A	N/A	None	0	0
J1706	Solar Machines	102.06	49.43	-49.43	None	N/A	N/A	1 - 26.4 Mvar Cap	26.4	0
J1708	Solar Machines	76.55	37.07	-37.07	None	N/A	N/A	None	0	0
J1716	Solar Machines	100.99	51.74	-51.74	None	N/A	N/A	None	0	0
J1719	Solar Machines	104.65	34.40	-34.40	None	N/A	N/A	1 - 10 Mvar Cap	10	0
J1720	Solar Machines	100.34	54.16	-54.16	None	N/A	N/A	None	0	0
J1732	Solar Machines	99.99	57.82	-57.82	None	N/A	N/A	None	0	0
J1735	Solar Machines	76.55	37.07	-37.07	None	N/A	N/A	None	0	0
J1740	Solar Machines	104.65	34.40	-34.40	None	N/A	N/A	None	0	0
J1745	Solar Machines	102.06	49.43	-49.43	None	N/A	N/A	None	0	0
J1746	Solar Machines	150.26	72.77	-72.77	None	N/A	N/A	None	0	0
J1750	Solar Machines	153.00	54.00	-54.00	None	N/A	N/A	1 - 27 Mvar Cap	27	0
J1751	Solar Machines	153.00	54.00	-54.00	None	N/A	N/A	1 - 29 Mvar Cap	29	0
J1752	Solar Machines	153.00	54.00	-54.00	None	N/A	N/A	1 - 29 Mvar Cap	29	0
J1773	Wind Turbines	303.00	146.75	-146.75	None	N/A	N/A	2 - 10 Mvar Cap	20	0
J1778	Solar Machines	100.00	48.50	-48.50	None	N/A	N/A	1 - 4 Mvar Cap	4	0
J1779	Solar Machines	200.00	96.90	-96.90	None	N/A	N/A	2 - 4 Mvar Cap	8	0
J1781	Wind Turbines	303.00	146.75	-146.75	None	N/A	N/A	2 - 10 Mvar Cap	20	0
J1793	Solar Machines	76.55	37.07	-37.07	None	N/A	N/A	None	0	0
J1244/J1803/J1817	Wind Turbines	60.00	29.1	-29.1	None	N/A	N/A	None	0	0

[redacted]

J1814	Solar Machines	23.05	11.16	-11.16	None	N/A	N/A	None	0	0
J1824	Solar Machines	75.00	43.34	-43.34	None	N/A	N/A	None	0	0
J1843	Simple Cycle	501[1]	303[1]	-141.3[1]	None	N/A	N/A	None	0	0

[1] Gross values. The generating facility auxiliary load were not included.

[redacted].

The dynamic capacitive power factor requirement analysis showed all requests meeting ATC Criteria and FERC Order 827 requirements. The results are summarized in Table 2.2-2.

Table 2.2-2 – Assessment of Dynamic Capacitive Power Factor Requirement

MISO Queue #	Machine Terminal Bus #	Capability at Machine Terminal		Additional Dynamic Capacitive Reactive Power[1] (Mvar)	Dynamic Power Factor Provided	Meets Requirement[2]?	Additional Requirement[3] (Mvar)
		Real Power Pmax (MW)	Capacitive Reactive Power Qmax (Mvar)				
J1497	44970	125.00	60.50	0.0	0.90	Yes	0
J1502	45020	227.92	116.77	0.0	0.89	Yes	0
J1508	45080	98.90	42.73	0.0	0.92	Yes	0
J1510	45100	103.88	44.25	0.0	0.92	Yes	0
J1512	45120	98.90	42.73	0.0	0.92	Yes	0
J1513	48140	304.22	129.60	0.0	0.93	Yes	0
J1567	45671	152.11	64.80	0.0	0.94	Yes	0
J1573	45730, 45731	254.6	82.00	0.0	0.95	Yes	0
J1615	46150	152.11	64.80	0.0	0.92	Yes	0
J1629	46290	203.29	104.15	0.0	0.89	Yes	0
J1706	47060	102.06	49.43	0.0	0.90	Yes	0
J1708	47080	76.55	37.07	0.0	0.90	Yes	0
J1716	47160	100.99	51.74	0.0	0.89	Yes	0
J1719	47190	104.65	34.40	0.0	0.95	Yes	0
J1720	47200	100.34	54.16	0.0	0.88	Yes	0
J1732	47320	99.99	57.82	0.0	0.87	Yes	0
J1735	47351	76.55	37.07	0.0	0.92	Yes	0
J1740	47400	104.65	34.40	0.0	0.95	Yes	0
J1745	47451	102.06	49.43	0.0	0.92	Yes	0
J1746	47460	150.26	72.77	0.0	0.90	Yes	0
J1750	47500	153.00	53.79	0.0	0.94	Yes	0
J1751	47510	153.00	54.00	0.0	0.94	Yes	0
J1752	47520	153.00	54.00	0.0	0.94	Yes	0
J1773	47730, 47731	303.00	146.75	0.0	0.90	Yes	0
J1778	47780	100.00	48.50	0.0	0.90	Yes	0
J1779	47790, 47791	200.00	96.90	0.0	0.90	Yes	0
J1781	47810, 47811	303.00	146.75	0.0	0.90	Yes	0

[redacted].

J1793	47931	76.55	37.07	0.0	0.92	Yes	0
J1244/J1803/J1817	42440, 42441, 48170	60.00	29.1	0.0	0.90	Yes	0
J1814	48141	23.05	11.16	0.0	0.92	Yes	0
J1824	48240	75.00	43.34	0.0	0.87	Yes	0
J1843	699137, 699138, 699139	501[4]	303[4]	0.0	0.86	Yes	0

[1] Dynamic capacitive reactive power provided by Interconnection Customer owned equipment in addition to the machine.
[2] ATC requires a 0.95 ATC Capacitive Dynamic Power Factor.
[3] Additional dynamic reactive power required to meet ATC Capacitive Dynamic Power Factor.
[4] Gross values. The generating facility auxiliary load were not included.

The static capacitive power factor requirement analysis showed that 12 requests do not meet the ATC Criteria or FERC Order 827 requirements. The results are summarized in Table 2.2-3.

Table 2.2-3 – Assessment of Static Capacitive Power Factor Requirement

MISO Queue #	Point of Measurement	Capability at Point of Measurement[1]		Power Factor	Meets Requirement?	Additional Requirement (Mvar)
		Real Power (MW)	Reactive Power (Mvar)			
J1497	44973	124.1	53.6	0.92	Yes	0
J1502	45023	223.0	72.6	0.95	Yes	0
J1508	45083	96.5	27.1	0.96	No	4.6
J1510	45103	100.6	47.7	0.90	Yes	0
J1512[2]	45125	96.63	30.45	0.95	Yes	0
J1513	45133	296.5	72.0	0.97	No	25.5
J1567	45673	150.0	53.7	0.94	Yes	0
J1573	45736	251.3	91.2	0.94	Yes	0
J1615	46153	150	53.9	0.94	Yes	0
J1629	46293	200.5	62.3	0.95	Yes	0
J1706	47063	100.2	26.5	0.97	No	6.4
J1708	47083	75.2	20.8	0.96	No	3.9
J1716	42534	99.9	34.8	0.94	Yes	0
J1719	47193	103.0	20.8	0.98	No	13.1
J1720	47203	99.0	33.0	0.95	Yes	0
J1732	47323	98.6	35.3	0.94	Yes	0
J1735	47353	75.2	20.8	0.96	No	3.9

J1740	47403	103	12.8	0.99	No	21.1
J1745	47453	101.5	43.5	0.97	No	6.4
J1746	47463	147.5	40.8	0.96	No	7.7
J1750	47503	149.6	62.2	0.92	Yes	0
J1751	47513	150.5	59.7	0.93	Yes	0
J1752	47523	148.7	69.8	0.91	Yes	0
J1773	47736	298.0	109.2	0.94	Yes	0
J1778	693358	97.9	36.2	0.94	Yes	0
J1779	43269	195.7	72.1	0.94	Yes	0
J1781	47816	298.0	111.5	0.94	Yes	0
J1793	47933	75.3	20.8	0.96	No	3.9
J1244/J1803/J1817	42446	58.7	17.5	0.96	No	1.8
J1814	48143	22.7	7.3	0.95	Yes	0
J1824	48243	74.0	26.3	0.94	Yes	0
J1843	699218	498.0	228.4	0.91	Yes	0

[1] Point of Measurement is the POI Bus for synchronous machines and high side of generator substation for asynchronous machines.

[2] The power factor study for J1512 was based on the latest configuration including a single 138/34.5 kV transformer.

The dynamic inductive power factor requirement analysis showed all but three of the requests meet ATC Criteria and FERC Order 827 requirements. The results are summarized in Table 2.2-4.

Table 2.2-4 – Assessment of Dynamic Inductive Power Factor Requirement

MISO Queue #	Machine Terminal Bus #	Capability at Machine Terminal		Additional Dynamic Inductive Reactive Power[1] (Mvar)	Dynamic Power Factor Provided	Meets Requirement[2]?	Additional Requirement[3] (Mvar)
		Real Power Pmax (MW)	Inductive Reactive Power Qmin (Mvar)				
J1497	44970	125.00	-60.50	0.0	0.90	Yes	0
J1502	45020	227.92	-116.77	0.0	0.89	Yes	0
J1508	45080	98.90	-30.35	0.0	0.96	No	2.16
J1510	45100	103.88	-44.25	0.0	0.92	Yes	0
J1512	45120	98.90	-30.35	0.0	0.96	No	2.16
J1513	45131	304.22	-129.60	0.0	0.87	Yes	0
J1567	45671	152.11	-64.80	0.0	0.90	Yes	0

J1573	45730, 45731	254.6	-82.00	0.0	0.95	Yes	0
J1615	46150	152.11	-64.80	0.0	0.92	Yes	0
J1629	46290	203.29	-104.15	0.0	0.89	Yes	0
J1706	47060	102.06	-49.43	0.0	0.90	Yes	0
J1708	47080	76.55	-37.07	0.0	0.90	Yes	0
J1716	47160	100.99	-51.74	0.0	0.89	Yes	0
J1719	47190	104.65	-34.40	0.0	0.95	Yes	0
J1720	47200	100.34	-54.16	0.0	0.88	Yes	0
J1732	47320	99.99	-57.82	0.0	0.87	Yes	0
J1735	47351	76.55	-37.07	0.0	0.87	Yes	0
J1740	47400	104.65	-34.40	0.0	0.95	Yes	0
J1745	47451	102.06	-49.43	0.0	0.87	Yes	0
J1746	47463	150.26	-72.77	0.0	0.90	Yes	0
J1750	47500	153.00	-54.00	0.0	0.92	Yes	0
J1751	47510	153.00	-54.00	0.0	0.94	Yes	0
J1752	47520	153.00	-54.00	0.0	0.94	Yes	0
J1773	47730, 47731	303.00	-146.75	0.0	0.90	Yes	0
J1778	47780	100.00	-48.50	0.0	0.90	Yes	0
J1779	47790, 47791	200.00	-96.90	0.0	0.90	Yes	0
J1781	47810, 47811	303.00	-146.75	0.0	0.90	Yes	0
J1793	47931	76.55	-37.07	0.0	0.87	Yes	0
J1244/J1803/J 1817	42440, 42441, 48170	60.00	-29.1	0.0	0.90	Yes	0
J1814	48141	23.05	-11.16	0.0	0.87	Yes	0
J1824	48240	75.00	-43.34	0.0	0.87	Yes	0
J1843	699137, 699138, 699139	501[4]	-141.3[4]	0.0	0.96	No	23.37

[1] Dynamic inductive reactive power provided by Interconnection Customer owned equipment in addition to the machine.
[2] ATC requires a 0.95 ATC Inductive Dynamic Power Factor.
[3] Additional dynamic reactive power required to meet ATC Inductive Dynamic Power Factor.
[4] Gross Values. The generating facility auxiliary load were not included.

The static inductive power factor requirement analysis showed all requests meeting ATC Criteria and FERC Order 827 requirements. The results are summarized in Table 2.2-5.

Table 2.2-5 – Assessment of Static Inductive Power Factor Requirement

[redacted].

MISO Queue #	POI Bus (synchronous) or HV Bus (asynchronous)	MW at POI (synchronous) or HV Bus (asynchronous)	Mvar at POI (synchronous) or HV Bus (asynchronous)	POI (synchronous) or HV Bus (asynchronous) Power Factor	Meets 0.95 ATC Inductive Power Factor Requirement at POI Bus (synchronous) or HV Bus (asynchronous)?
J1497	44973	121.9	-76.7	0.85	Yes
J1502	45023	222.1	-170.1	0.79	Yes
J1508	45083	96.6	-44.7	0.91	Yes
J1510	45103	100.0	-63.6	0.84	Yes
J1512[1]	45125	96.8	-40.9	0.92	Yes
J1513	45133	294.5	-266.7	0.79	Yes
J1567	45673	149.7	-99.2	0.83	Yes
J1573	45736	251.2	-127.1	0.89	Yes
J1615	46153	149.7	-98.9	0.83	Yes
J1629	46293	199.9	-155.1	0.79	Yes
J1706	47063	99.8	-77.7	0.79	Yes
J1708	47083	75.0	-56.5	0.80	Yes
J1716	42534	99.8	-70.2	0.82	Yes
J1719	47193	102.8	-59.8	0.86	Yes
J1720	47203	98.7	-80.5	0.77	Yes
J1732	47323	98.2	-87.6	0.75	Yes
J1735	47353	75.0	-56.5	0.80	Yes
J1740	47403	102.9	-57.4	0.87	Yes
J1745	47453	99.8	-77.7	0.79	Yes
J1746	47463	146.9	-111.3	0.80	Yes
J1750	47503	149.6	-71.2	0.90	Yes
J1751	47513	150.5	-75.7	0.89	Yes
J1752	47523	148.6	-65.3	0.92	Yes
J1773	47736	297.2	-212.4	0.81	Yes
J1778	693358	97.6	-67.1	0.82	Yes
J1779	43269	195.1	-134.3	0.82	Yes
J1781	47816	297.2	-209.6	0.82	Yes
J1793	47933	75.0	-56.5	0.80	Yes
J1244/J1803/J1817	42446	58.5	-42.9	0.81	Yes
J1814	48143	22.7	-15.4	0.83	Yes
J1824	48243	73.7	-65.7	0.75	Yes

[redacted].

J1843	699218	498.4	-200.2	0.93	Yes

[1] The power factor study for J1512 was based on the latest configuration including a single 138/34.5 kV transformer.

When non-synchronous Generating Facility is not generating active power (i.e. zero MW output), the reactive power injection to the transmission system at the high-side of the generator substation should be zero Mvar. Table 1.2.2-2 shows the Mvar levels expected at the high-side of the generator substations for all non-synchronous generation requests when not generating. Inductive power devices or the generating facilities inverters can be used to counter var flows created at low or no output levels.

Table 2.2-6 – Assessment of Reactive Power Injection to the Transmission System When Non-synchronous Generator is at zero MW output

MISO Queue #	Additional inductive Mvar required at the high side of generator substation to meet ATC Power Factor Requirement when non-synchronous generator is at zero MW output
J1497	14.3
J1502	5.3
J1508	5.5
J1510	9.1
J1512	5.5
J1513	1.2
J1567	0.6
J1573	4.0
J1615	0.6
J1629	3.4
J1706	0.9
J1708	0.6
J1716	0.1
J1719	1.5
J1720	1.2
J1732	1.1
J1735	0.6
J1740	1.5
J1745	0.9
J1746	1.5
J1750	11.7
J1751	6.5
J1752	19.0

J1773	2.8
J1778	5.3
J1779	10.7
J1781	5.6
J1793	0.6
J1244/J1803/J1817	1.4
J1814	0.1
J1824	0.7

[1] The power factor study for J1512 was based on the latest configuration including a single 138/34.5 kV transformer.

2.3 NERC TPL Contingency Analysis Results

The incremental impact of the proposed generator interconnection on transmission facilities was evaluated by comparing steady state power flows and voltages between benchmark cases (without DPP 2020 Cycle Phase 1 projects) and study cases (with DPP 2020 Cycle Phase 1 projects). Post-contingency cases were solved with transformer tap adjustment enabled, area interchange adjustment disabled, phase shifter adjustment enabled, and switched shunt adjustment enabled. Detailed NERC TPL Category P contingencies that were studied are described in Table A.2.1-1 in Appendix A.

2.3.1 2025 Summer Peak Batteries Discharging

The study identified the steady-state thermal constraints that qualified as MISO Injection Constraints in the 2025 Summer Peak Discharging study model under NERC Category P0-P7 Planning Events (except NERC Category P3 and P6). Detailed steady-state power flow results and Injection Constraint determination can be found in Appendix E. A summary of the 2025 Summer Peak Discharging MISO Injection Constraints that require Network Upgrades is presented in Table 2.3.1. No voltage constraints were identified in the steady-state analyses.

Table 2.3.1 – 2025 Summer Peak Batteries Discharging Steady-State Injection Constraints Requiring Network Upgrades

Study Case	Overloaded Facility	Facility Owner	Resulted by "No Load Loss Allowed"[1] NERC TPL Planning Events	Responsible Generator(s)
2025 Summer Discharging	J986 POI – Port Edwards 138 kV line	ATC	Base, P1.1, P1.2, P1.3, P2.1, P2.3 EHV	J1719, J1720, J1751, J1824
	Hancock – Sand Lake Tap 69 kV line	ATC	P1.2, P2.1, P1.3	J1719
	Academy 138/69 kV transformer	ATC	P1.2, P2.1	J1720, J1824
	North Randolph – Green Lake 138 kV line	ATC	P1.2	J1629

	Koshkonong – Kegonsa 138 kV line	ATC	P1.2	J1843

[1] The "No Load Loss Allowed' NERC TPL Planning Events refer to all the Planning Events in NERC TPL-001-4 Table 1 that the interruption of Firm Transmission Service and Non-Consequential Load Loss are not allowed.

[2] Per ATC's Planning Criteria, for Planning Events that allow Non-Consequential load loss, short duration exposure to potential post-contingency overload represents an acceptable risk assuming system adjustment within that short period of time can eliminate the exceedance and restore facility loading within Long-Term emergency ratings.

2.3.2 2025 Shoulder Batteries Discharging

The study identified the steady-state thermal constraints that qualified as MISO Injection Constraints in the 2025 Shoulder Discharging study model under NERC Category P0-P7 Planning Events (except NERC Category P3 and P6). Detailed steady-state power flow results and Injection Constraint determination can be found in Appendix E. A summary of the 2025 Shoulder Discharging MISO Injection Constraints that require Network Upgrades is presented in Table 2.3.2. No voltage constraints were identified in the steady state analyses.

Table 2.3.2 – 2025 Shoulder Batteries Discharging Steady-State Injection Constraints Requiring Network Upgrades

Study Case	Overloaded Facility	Facility Owner	Resulted by "No Load Loss Allowed"[1] NERC TPL Planning Events	Responsible Generator(s)
2025 Shoulder Discharging	North Monroe – Albany 138 kV line	ATC	P1.3, P2.3 EHV	J1512
	J1305 POI – Albany 138 kV line	ATC	P1.2, P1.3, P2.3 EHV	J1512
	J1305 POI – Bass Creek 138 kV line	ATC	P1.2, P1.3, P2.3 EHV	J1512
	Klondike Tap – Darlington 138 kV line	ATC	P1.2, P1.3, P2.3 EHV	J1512, J1773, J1781
	Klondike Tap – North Monroe 138 kV line	ATC	P1.2, P1.3, P2.3 EHV	J1512, J1773, J1781
	South Monroe – Browntown 69 kV line	ATC	P1.2, P2.1	J1512
	Highland – Eden 138 kV line	ATC	P1.2, P2.3 EHV	J1773, J1781
	Highland – Wyoming Valley 138 kV line	ATC	P1.2	J1773
	Spring Green – Wyoming Valley 138 kV line	ATC	P1.2	J1773
	Hill Valley – Eden 138 kV line	ATC	P1.2, P2.3 EHV	J1773, J1781

[1] The "No Load Loss Allowed' NERC TPL Planning Events refer to all the Planning Events in NERC TPL-001-4 Table 1 that the interruption of Firm Transmission Service and Non-Consequential Load Loss are not allowed.

[2] Per ATC's Planning Criteria, for Planning Events that allow Non-Consequential load loss, short duration exposure to potential post-contingency overload represents an acceptable risk assuming system adjustment within that short period of time can eliminate the exceedance and restore facility loading within Long-Term emergency ratings.

2.3.3 Network Upgrades Identified in ERIS Analysis

Based on the steady-state analyses, the worst loading of each facility under "No Load Loss Allowed" NERC TPL Planning Events that meets MISO Injection Constraint criteria is shown in Table 2.3.3-1. Identified Network Upgrades are also included. Good faith Cost Estimates of the ERIS thermal Network Upgrades identified in the steady-state analysis for the 2025 scenarios are listed in Table 2.3.3-2. Detailed cost allocations are provided in Section 9.

[redacted] [redacted].

Table 2.3.3-1 – ERIS Network Upgrades Identified to Address MISO Steady-State Injection Constraints

Steady-State Injection Constraint	Responsible Generator(s)	Facility Owner	Study Case	Applicable Rating (MVA)	Worst Loading (%)	"No Load Loss Allowed" NERC TPL Planning Event	Network Upgrades
J986 POI – Port Edwards 138 kV line	J1719, J1720, J1751, J1824	ATC	25SUM, Batteries Discharging	155	123.2	[redacted]	7 Mile Creek - Port Edwards 138 kV (X-159), rebuild
Hancock – Sand Lake Tap 69 kV line	J1719	ATC	25SUM, Batteries Discharging	45	156.47	[redacted]	Sand Lake - Hancock 69 kV (Y-90), uprate
Academy 138/69 kV transformer	J1720, J1824	ATC	25SUM, Batteries Discharging	96	131.08	[redacted]	Academy SS, transformer replacement
North Randolph – Green Lake 138 kV line	J1629	ATC	25SUM, Batteries Discharging	158	111.25	[redacted]	North Randolph - Green Lake 138 kV (X-30), uprate
Koshkonong – Kegonsa 138 kV line	J1843	ATC	25SUM, Batteries Discharging	389	102.78	[redacted]	Kegonsa-Koshkonong 138 kV (G-CHR21), uprate
North Monroe – Albany 138 kV line	J1512	ATC	25SH, Batteries Discharging	146	101.9	[redacted]	North Monroe - J1305 POI 138 kV (X-12), uprate
J1305 POI – Albany 138 kV line	J1512	ATC	25SH, Batteries Discharging	120	121.18	[redacted]	
J1305 POI – Bass Creek 138 kV line	J1512	ATC	25SH, Batteries Discharging	120	121.03	[redacted]	Bass Creek - J1305 POI 138 kV (X-12), uprate
Klondike Tap – Darlington 138 kV line	J1512, J1773, J1781	ATC	25SH, Batteries Discharging	181	111.04	[redacted]	Darlington - North Monroe 138 kV (X-49), uprate
Klondike Tap – North Monroe 138 kV line	J1512, J1773, J1781	ATC	25SH, Batteries Discharging	181	110.87	[redacted]	
South Monroe – Browntown 69 kV line	J1512	ATC	25SH, Batteries Discharging	59	114.02	[redacted]	South Monroe - Brown Town 69 kV (Y-155), rebuild
Highland – Eden 138 kV line	J1773, J1781	ATC	25SH, Batteries Discharging	335	116.19	[redacted]	Eden - Highland 138 kV (X-147), rebuild
Highland – Wyoming Valley 138 kV line	J1773	ATC	25SH, Batteries Discharging	309	105.43	[redacted]	Highland - Spring Green 138 kV (X-17), reconductor
Spring Green – Wyoming Valley 138 kV line	J1773	ATC	25SH, Batteries Discharging	309	104.71	[redacted]	
Hill Valley – Eden 138 kV line	J1773, J1781	ATC	25SH, Batteries Discharging	402	118.25	[redacted]	Hill Valley - Eden 138 kV (X-127), rebuild

Table 2.3.3-2 – ERIS Network Upgrades and Cost Estimates

Steady-State Injection Constraint	Facility Owner	Network Upgrade	Cost ($)[1,2]
J986 POI – Port Edwards 138 kV line	ATC	7 Mile Creek - Port Edwards 138 kV (X-159), rebuild	7,011,343
Hancock – Sand Lake Tap 69 kV line	ATC	Sand Lake - Hancock 69 kV (Y-90), uprate	1,430,384
Academy 138/69 kV transformer	ATC	Academy SS, transformer replacement	4,001,020
North Randolph – Green Lake 138 kV line	ATC	North Randolph - Green Lake 138 kV (X-30), uprate	2,405,225
Koshkonong – Kegonsa 138 kV line	ATC	Kegonsa - Koshkonong 138 kV (G-CHR21), uprate	1,095,926
North Monroe – Albany 138 kV line	ATC	North Monroe - J1305 POI 138 kV (X-12), uprate	696,625
J1305 POI – Albany 138 kV line	ATC		
J1305 POI – Bass Creek 138 kV line	ATC	Bass Creek - J1305 POI 138 kV (X-12), uprate	656,262
Klondike Tap – Darlington 138 kV line	ATC	Darlington - North Monroe 138 kV (X-49), uprate	481,688
Klondike Tap – North Monroe 138 kV line	ATC		
South Monroe – Browntown 69 kV line	ATC	South Monroe - Brown Town 69 kV (Y-155), rebuild	10,175,216
Highland – Eden 138 kV line	ATC	Eden - Highland 138 kV (X-147), rebuild	5,521,348
Highland – Wyoming Valley 138 kV line	ATC	Highland - Spring Green 138 kV (X-17), reconductor	7,333,800
Spring Green – Wyoming Valley 138 kV line	ATC		
Hill Valley – Eden 138 kV line	ATC	Hill Valley - Eden 138 kV (X-127), rebuild	2,584,001

[1] All Network Upgrades were estimated on the responsible generator earliest ISD dollars.
[2] ATC Network Upgrades included a contingency based on a project risk generally between 5% – 20%.

2.3.4 Network Upgrade Alternatives Considered

The ERIS network upgrades identified in Table 2.3.3-2 are direct upgrades of the ERIS thermal constraint facilities to ATC design standards and considered as least-cost solutions. Therefore, no other alternatives were examined for those solutions.

2.3.5 Potential Operating Restriction

Operating restriction analysis will be performed as part of MISO DPP 2020 Cycle Phase 2.

2.4 J1502 Additional Studies

Due to unique concerns with the location of the J1502 POI, ATC performed the following additional studies, which are included in Appendix K.

1. Delayed Current Zeros (DCZ)

The Briggs Road – J1502 POI 345 kV line requires that the Briggs Road 345 kV reactor be switched out [redacted] to prevent the possibility of DCZs. While DCZs were not identified in J1502 POI – North Madison simulations, there is still a possibility that DCZs will occur, therefore the North Madison 345 kV reactor will be switched out [redacted]. The North Madison 345 kV reactor and the Briggs Road 345 kV reactor will be automatically switched in based on local bus voltage to prevent the possibility of sustained over-voltages [redacted].

2. Steady State Line Energization

   Both the Briggs Road – J1502 POI and J1502 POI – North Madison 345 kV lines can be energized in a light load model without any other outages, while respecting ATC and Xcel local emergency maximum voltage limits. To prevent extreme over-voltages when the lines are being energized during local outages, the automatic reclosing systems will be designed to energize Briggs Road – J1502 POI 345 kV from the J1502 POI (the first breaker closed will be at J1502 POI) and to energize J1502 POI – North Madison 345 kV from North Madison (the first breaker closed will be at North Madison).

3. Steady State Voltage

   There are no steady state voltage violations identified after the interconnection of J1502. Steady state voltage was also analyzed assuming individual outages of [redacted] with no identified violations of the maximum emergency voltage limits.

4. Coupled Line Resonance

   Both 345 kV lines can be de-energized with the shunt reactors connected while respecting the design voltage of the lines.

5. Steady State Voltage Stability Sensitivity

   The findings in this sensitivity analysis do not require nor prevent the definition of local Planning or Operating System Operating Limits.

6. Modification of Existing Protection Systems

   In addition to the automatic switching of shunt reactors and reclosing system changes described above, the maximum reclosing angles will be reduced to 40 degrees and the existing over-voltage tripping system at Briggs Road and North Madison will be adjusted to include the J1502 POI.

3.0 STABILITY ANALYSIS

Stability analysis will be performed as part of MISO DPP 2020 Cycle Phase 2.

4.0 SHORT CIRCUIT ANALYSIS

Short circuit analysis will be performed as part of MISO DPP 2020 Cycle Phase 2.

[redacted].

5.0 TRANSFORMER ENERGIZATION ANALYSIS

5.1 Transformer Energization Study Results

Transformer Energization Analysis were performed based on ATC transformer initial energization criteria as described in Appendix A. The 2025 shoulder model (batteries charging) was used with all identified ERIS and NRIS Network Upgrades included. The results are summarized in Table 5.1-1. The only constraint found was for J1512 where the minimum voltage (0.692) fell just below the 0.70 allowed minimum. If J1512 decides to go forward, this issue can be addressed by (1) the developer commissioning a detailed EMT study to determine if the minimum voltage is acceptable, (2) the generator changing their project's design (increasing the transformer impedance), or (3) using controlled closing when energizing the transformer to reduce inrush currents.

Table 5.1-1 – Inrush Calculations Using Shoulder Model

Generation Project	Transformer(s)		PSSE POI	Fault	Vmin Inrush (pu)	
	Number	Windings	Bus #	Current (A)	Raw	Multiplier
J1497	1	3	698887	11940	0.877	1.009
J1502	1	3	45024	6551	0.818	0.941
J1508	1	3	45084	4839	0.653	0.751
J1510	1	3	45104	8785	0.942	1.083
J1512	1	3	699033	5232	0.602	0.692
J1513	2	3	694031	10640	0.930	1.069
J1567	1	3	698929	17437	0.898	1.033
J1573	2	3	699787	13554	0.865	0.995
J1615	1	3	699593	17889	0.901	1.036
J1629	1	3	46294	11753	0.922	1.060
J1706	1	3	699036	5066	0.813	0.935
J1708	1	3	693344	5659	0.856	0.985
J1716	1	3	42535	11587	0.916	1.053
J1719	1	3	699939	5532	0.834	0.959
J1720	1	3	47204	10662	0.897	1.032
J1732	1	3	47324	9452	0.887	1.020
J1735	1	3	43044	16973	0.947	1.089
J1740	1	3	47404	13599	0.917	1.055
J1745	1	3	699670	18061	0.940	1.080
J1746	1	3	699167	22805	0.925	1.064
J1750	1	3	47504	5664	0.697	0.802

J1751	1	3	47514	7322	0.741	0.853
J1752	1	3	699791	5007	0.669	0.769
J1773	2	3	47737	10980	0.930	1.070
J1778	1	3	699409	27299	0.951	1.094
J1779	2	3	73270	17250	0.969	1.114
J1781	2	3	693863	11311	0.933	1.073
J1793	1	3	699288	7193	0.883	1.016
J1803	1	3	42447	3184	0.826	0.950
J1814	1	3	699566	5595	0.933	1.073
J1817	1	3	42447	3184	0.826	0.950
J1824	1	3	699169	9459	0.913	1.050
J1843	3	2	699218	29670	0.922	1.060

[redacted].

6.0 LOW SHORT CIRCUIT STRENGTH SCREENING ANALYSIS

ATC performed a low short circuit strength screening analysis for all inverter-based resources in the DPP 2020 Cycle Phase 1 East (ATC) area. The methodology for the low short circuit strength screening analysis is detailed in Appendix B. PSCAD analysis will be performed as part of MISO DPP 2020 Cycle Phase 2.

6.1 Low Short Circuit Strength Screening Results

The low short circuit strength screening analysis included classic Short Circuit Ratio (SCR) analysis with results shown in Tables 6.1-1, 6.1-2, and 6.1-3.

Table 6.1-1: SCR Analysis Results for System Intact

MISO Queue #	POI Bus #	Capacity (MW)	Short Circuit Capacity (MVA)	Short Circuit Ratio at POI
J1497	698887	125	2,489	19.9
J1502	45024	225	3,884	17.3
J1508	45084	98.9	1,083	10.9
J1510	694002	100	5,291	52.9
J1512	699033	98.9	1,277	12.9
J1513	694028	300	6,463	21.5
J1567	694082	150	4,213	28.1
J1573	699787	250	2,723	10.9
J1615	699570	150	4,341	28.9
J1629	46294	200	7,136	35.7
J1706	699036	100	1,274	12.7
J947/J1708	89475	275	1,296	4.7
J1253/J1716	42535	200	7,270	36.3
J1719	699939	100	1,278	12.8
J1720	47204	99	2,581	26.1
J1732	47324	98.4	2,269	23.1
J1735	43044	205	5,213	25.4
J1740	47404	100	2,498	25.0
J1745	699670	100	4,394	43.9
J1746	699167	150	5,394	36.0
J1750	699336	149.69	959	6.4
J1751	47514	150.5	1,745	11.6
J1752	699791	148.1	1,205	8.1
J1773	47737	300	5,623	18.7
J878/J1316/J1778	699409	100	5,223	14.9
J1214/J1326/J1779	73270	575	9,962	17.3
J1483/J1781	693863	300	5,791	19.3
J1153/J1793	699288	225	1,520	6.8

J1244/J1803/J1817	42447	60	378	6.3
J1814	699566	22.5	1,361	60.5
J1824	699169	73.8	2,285	31.0

Table 6.1-2: SCR Analysis Results for Worst N-1 Contingency

MISO Queue #	POI Bus #	Capacity (MW)	Short Circuit Capacity (MVA)	Short Circuit Ratio at POI
J1497	698887	125	1,587	12.7
J1502	45024	225	1,208	5.4
J1508	45084	98.9	343	3.5
J1510	694002	100	2,092	20.9
J1512	699033	98.9	650	6.6
J1513	694028	300	4,439	14.8
J1567	694082	150	2,135	14.2
J1573	699787	250	1,919	7.7
J1615	699570	150	2,613	17.4
J1629	46294	200	2,424	12.1
J1706	699036	100	675	6.7
J947/J1708	89475	275	642	2.3
J1253/J1716	42535	200	3,790	18.9
J1719	699939	100	719	7.2
J1720	47204	99	929	9.4
J1732	47324	98.4	598	6.1
J1735	43044	205	2,570	12.5
J1740	47404	100	805	8.1
J1745	699670	100	3,414	34.1
J1746	699167	150	3,905	26.0
J1750	699336	149.69	572	3.8
J1751	47514	150.5	403	2.7
J1752	699791	148.1	565	3.8
J1773	47737	300	2,897	9.7
J878/J1316/J1778	699409	100	2,937	8.4
J1214/J1326/J1779	73270	575	8,105	14.1
J1483/J1781	693863	300	3,494	11.6
J1153/J1793	699288	225	356	1.6
J1244/J1803/J1817	42447	60	180	3.0
J1814	699566	22.5	615	27.3
J1824	699169	73.8	1,174	15.9

Table 6.1-3: SCR Analysis Results for Worst N-1-1 Contingency

MISO Queue #	POI Bus #	Capacity (MW)	Short Circuit Capacity (MVA)	Short Circuit Ratio at POI
J1497	698887	125	776	6.2
J1502	45024	225	871	3.9
J1508	45084	98.9	254	2.6
J1510	694002	100	702	7.0
J1512	699033	98.9	256	2.6
J1513	694028	300	2,149	7.2
J1567	694082	150	934	6.2
J1573	699787	250	855	3.4
J1615	699570	150	2,088	13.9
J1629	46294	200	1,896	9.5
J1706	699036	100	275	2.7
J947/J1708	89475	275	205	0.7
J1253/J1716	42535	200	1,494	7.5
J1719	699939	100	190	1.9
J1720	47204	99	269	2.7
J1732	47324	98.4	217	2.2
J1735	43044	205	1,252	6.1
J1740	47404	100	591	5.9
J1745	699670	100	1,805	18.1
J1746	699167	150	1,512	10.1
J1750	699336	149.69	361	2.4
J1751	47514	150.5	186	1.2
J1752	699791	148.1	123	0.8
J1773	47737	300	1,140	3.8
J878/J1316/J1778	699409	100	1,726	4.9
J1214/J1326/J1779	73270	575	5,798	10.1
J1483/J1781	693863	300	1,222	4.1
J1153/J1793	699288	225	353	1.6
J1244/J1803/J1817	42447	60	101	1.7
J1814	699566	22.5	291	12.9
J1824	699169	73.8	287	3.9

It was determined that several groups of inverter-based resources were placed sufficiently close together to require Weighted Short Circuit Ratio (WSCR) analysis. The results for these WSCR analyses are shown in Tables 6.1-4, 6.1-5, and 6.1-6.

Table 6.1-4: WSCR Analysis Results for System Intact

Generator Group	Weighted SCR
Zone 1: J986, J1002, J1719	7.9
NED-BCK 138 kV: Quiltblock, J947, J1305, J1512, J1706, J1708, J1711	1.8
NED-SPG 138 kV: J855, J870, J871, J1000, J1374	4.7
NED-SPG 138 kV + HLV 345 kV: J855, J870, J871, J1000, J1374, 1483, J1773, J1781	3.5
SW WI 138 kV: Quiltblock, J855, J870, J871, J947, J1000, J1781, J1305, J1374, J1483, J1512, J1706, J1708, J1773	1.6

Table 6.1-5: WSCR Analysis Results for Worst N-1 Contingency

Generator Group	Weighted SCR
Zone 1: J986, J1002, J1719	3.7
NED-BCK 138 kV: Quiltblock, J947, J1305, J1512, J1706, J1708, J1711	1.3
NED-SPG 138 kV: J855, J870, J871, J1000, J1374	2.3
NED-SPG 138 kV + HLV 345 kV: J855, J870, J871, J1000, J1374, 1483, J1773, J1781	2.3
SW WI 138 kV: Quiltblock, J855, J870, J871, J947, J1000, J1781, J1305, J1374, J1483, J1512, J1706, J1708, J1773	1.1

Table 6.1-6: WSCR Analysis Results for Worst N-1-1 Contingency

Generator Group	Weighted SCR
Zone 1: J986, J1002, J1719	2.0
NED-BCK 138 kV: Quiltblock, J947, J1305, J1512, J1706, J1708, J1711	0.8
NED-SPG 138 kV: J855, J870, J871, J1000, J1374	1.4
NED-SPG 138 kV + HLV 345 kV: J855, J870, J871, J1000, J1374, 1483, J1773, J1781	1.0
SW WI 138 kV: Quiltblock, J855, J870, J871, J947, J1000, J1781, J1305, J1374, J1483, J1512, J1706, J1708, J1773	0.9

Application of the ATC Low Short Circuit Strength Guideline determined that J1508, J1512, J1706, J1708, J1719, J1720, J1732, J1735, J1750, J1751, J1752, J1773, J1781, J1793, J1803, J1817, and J1824 will all require detailed PSCAD studies to be performed to assess stability. Table 6.1-7 below summarizes the rationale for the PSCAD analysis decision for each queue request.

Table 6.1-7: Required PSCAD Studies and Rationale

MISO Queue #	Low SCR	Low WSCR	East of Arnold Substation	Operational / Previous Study Experience	PSCAD Study Required?
J1497	6.2	N/A	no	no	no
J1502	3.9	N/A	no	no	no
J1508	2.6	N/A	no	no	yes
J1510	7.0	N/A	no	no	no
J1512	2.6	0.8	no	yes	yes
J1513	7.2	N/A	no	no	no

[redacted]

J1567	6.2	N/A	no	no	no
J1573	3.4	N/A	no	no	no
J1615	13.9	N/A	no	no	no
J1629	9.5	8.8	no	no	no
J1706	2.7	0.8	no	yes	yes
J947/J1708	0.7	0.8	no	yes	yes
J1253/J1716	7.5	N/A	no	no	no
J1719	1.9	2.0	no	yes	yes
J1720	2.7	N/A	no	no	yes
J1732	2.2	N/A	no	no	yes
J1735	6.1	N/A	no	yes	yes
J1740	5.9	N/A	no	no	no
J1745	18.1	N/A	no	no	no
J1746	10.1	N/A	no	no	no
J1750	2.4	N/A	no	no	yes
J1751	1.2	N/A	no	no	yes
J1752	0.8	N/A	no	no	yes
J1773	3.8	1.0	no	yes	yes
J878/J1316/J1778	4.9	N/A	no	no	no
J1214/J1326/J1779	10.1	N/A	no	no	no
J1483/J1781	4.1	0.9	no	yes	yes
J1153/J1793	1.6	N/A	no	yes	yes
J1244/J1803/J1817	1.7	N/A	no	yes	yes
J1814	12.9	N/A	no	no	no
J1824	3.9	N/A	no	no	yes

7.0 AFFECTED SYSTEM ANALYSIS

Affected system analyses will be performed as part of MISO DPP 2020 Cycle Phase 2.

8.0 DELIVERABILITY STUDY

Generator interconnection requests have to pass Generator Deliverability Study to be granted Network Resource Interconnection Services (NRIS). If the generator is determined as not fully deliverable, the customer can either choose to elect the amount of NRIS available without upgrades or build system upgrades that will make the generator fully deliverable. Generator Deliverability Study ensures that the Network Resources, on an aggregate basis, can meet the MISO aggregate load requirements during system peak condition without getting bottled up.

MISO Generator Deliverability Study methodology is described in MISO BPM-15.

8.1 Study Summary

The summary of MISO deliverability results based on the 2025 summer peak study model is shown in the following tables. Detailed NRIS study results and individual generator summaries can be found in Appendix I.

Table 8.1-1 below lists the deliverability results with ERIS upgrades included in the NRIS analysis. Minimum NR Deliverable is the amount of service to be granted if none of the projects contributing to this constraint, reduced service levels or withdrew. Maximum NR Deliverable is the service level attainable if all projects contributing to the constraint, reduced their requested NR by the shared deduction.

Table 8.1-1 – NRIS Analysis Summary

MISO Queue #	Area	NR Tested (MW)	Minimum NR Deliverable (MW)	Maximum NR Deliverable (MW)
J1497	ATC	125	0	15.02
J1502	ATC	225	0	24.34
J1508	ATC	98.9	0	10.7
J1510	ATC	100	0	10.82
J1512	ATC	98.9	0	0
J1513	ATC	300	0	32.45
J1567	ATC	150	0	18.02
J1573	ATC	125	0	27.04
J1615	ATC	150	0	18.02
J1629	ATC	200	0	21.63
J1706	ATC	100	0	0
J1708	ATC	75	0	8.11
J1716	ATC	100	0	12.01
J1719	ATC	100	0	0
J1720	ATC	99	0	10.71
J1732	ATC	99.99	0	10.82
J1735	ATC	75	0	0
J1740	ATC	100	0	0
J1745	ATC	100	0	12.01
J1746	ATC	150	0	16.23
J1750	ATC	149.7	0	17.99
J1751	ATC	150.5	0	16.28
J1752	ATC	148.1	0	16.02
J1773	ATC	150	0	32.46
J1778	ATC	100	0	48.18
J1779	ATC	100	0	21.64
J1781	ATC	150	0	32.46
J1793	ATC	75	0	9.01
J1803	ATC	1.6	0	0.19
J1814	ATC	22.5	0	2.7
J1817	ATC	20	0	2.4
J1824	ATC	75	0	8.11
J1843	ATC	12	0	3.9

Table 8.1-2 below lists all of the NRIS constraints from the deliverability study and the identified NRIS Network Upgrades. Both ERIS Network Upgrades and NRIS Network Upgrades must be made for 100% NRIS, i.e. fully deliverable. Please note, if a NRIS Network Upgrade entirely or partially changes the scope of an ERIS Network Upgrade,

[redacted].

only the cost difference between the NRIS upgrade and the ERIS upgrade will be eligible for NRIS Network Upgrade cost allocation.

Due to the queue size and a large number of study generators in different MISO regions that were identified to be responsible for the NRIS Network Upgrades, considering readability, both the individual generator deliverability report and the detailed NRIS Network Upgrade cost allocation information including worst MW impact and cost allocation percentage are provided in Appendix I.

Table 8.1-2 – Network Upgrades Needed to Address MISO Identified NRIS Steady-State Injection Constraints

NRIS Thermal Constraints	Required NRIS Network Upgrades	Network Upgrade Owner	NRIS Network Upgrade Cost Estimates ($) [a]	ERIS Network Upgrade (Identified for Same Constraint) Cost Estimate ($) [b]	Previous Cycle ERIS/NRIS Network Upgrade (Identified for Same Constraint) Cost Estimate ($) [c]	Cost Used for NRIS Network Upgrade Allocation ($) [d] = [a] - [b] - [c]
43388 J1363 POI 345 43524 J1352 POI 345 1	J1352 - J1363 345 kV, Rebuild	Ameren	3,000,000			3,000,000
43388 J1363 POI 345 43524 J1352 POI 345 1 C						
43386 J1338 POI 345 43388 J1363 POI 345 1	J1363 - J1338 345 kV, Rebuild	Ameren	16,000,000			16,000,000
43386 J1338 POI 345 43388 J1363 POI 345 1 C						
43524 J1352 POI 345 345230 7MONTGMRY 345 1	Montgomery - J1352 345 kV, Rebuild	Ameren	5,000,000			5,000,000
43524 J1352 POI 345 345230 7MONTGMRY 345 1 C						
345992 7SPENCER 345 43386 J1338 POI 345 1	Spencer Creek - J1338 345 kV, Rebuild	Ameren	3,000,000			3,000,000
698090 BOL 138 138 699086 ELK 138 138 1	Bristol – Elkhorn 138 kV (X-81), uprate	ATC	665,914		243,377	422,537
699283 CONCRD 4 138 699293 COONEY 138 1	Concord – Bark River 138 kV, New Line	ATC	34,353,926			34,353,926
693580 CYPRESS 345 699247 ARCADIAN 345 345 1	Cypress – Arcadian 345 kV (L-CYP31), uprate	ATC	2,116,487			2,116,487
698007 DAR 69 69.0 698018 ROB 69 69.0 1	Darlington – Rock Branch 69 kV (Y-109), uprate	ATC	200,469			200,469
699086 ELK 138 138 699085 NLG 138 138 1	Elkhorn – North Lake Geneva 138 kV (X-55), uprate	ATC	702,477		52,259	650,218
693354 PARIS BUS2 345 270942 ZION STA ;0B 345 1	Elm Road – Mount Pleasant 345kV, New Line	ATC	46,429,634			46,429,634
694119 RACINE BUS5 345 693481 MT PLEASANT 345 1						
694121 RACINE BUS7 345 693481 MT PLEASANT 345 2						
699247 ARCADIAN 345 345 699432 PLS PR1 345 1						
699367 ELM ROAD 345 694120 RACINE BUS6 345 1						
699329 GRANVL1 345 699247 ARCADIAN 345 345 1	Granville – Arcadian 345 kV (9911), uprate	ATC	3,885,243			3,885,243
698870 GRANVL2 345 699329 GRANVL1 345 Z	Granville SS, 345kV Ring Bus (MTEP PID: 16490 Target A in MTEP21)	ATC	0			0
699327 GRANVL 5 138 699268 BUTLER 138 1	Granville-Butler 138kV (3453) and Granville-Tosa 138kV (3443), rebuild	ATC	22,843,826			22,843,826
699331 GRANVL 4 138 699492 TOSA-W 138 1						
43054 J1305 POI 138 699897 BASSCRK 138 1 C	J1305 POI – Bass Creek 138kV (X-12), reconductor	ATC	4,343,432			4,343,432
698995 MASS 69.0 698997 BRUCE CR 69.0 1	Mass – Bruce Crossing 69 kV (6530), uprate	ATC	6,088,262		540,191	5,548,071
693481 MT PLEASANT 345 699432 PLS PR1 345 1	New 345 kV switching station for 2222, PLPL81, L-ERG71	ATC	25,531,789			25,531,789
693481 MT PLEASANT 345 699432 PLS PR1 345 2						
999903 NEWSTATION 345 270876 ROSECRANS; B 345 1	New Switching Station – Rosecrans 345 kV (PLPL81), uprate	ATC	3,515,109			3,515,109
699360 NLK GV T 138 699267 BRLGTN1 138 1	North Lake Geneva Tap – Burlington 138kV (6541), rebuild	ATC	11,583,000			11,583,000
699036 NOM 138 138 698028 NOM 69 69.0 1	North Monroe SS, 138/69 kV transformer replacement	ATC	3,841,935			3,841,935
699409 PARIS B5 138 693647 BERRYVILLE 138 1	Paris SS, 2nd 345/138kV Transformer	ATC	8,598,800			8,598,800
699141 TOWNLINE 138 699047 ROR 138 138 2	Rock River – Townline Road 138 kV (X-74), uprate	ATC	391,848			391,848
694066 ROCKY RN B6 345 694082 WERNER W B4 345 1	Rocky Run – Werner West 345 kV (WERWL41), uprate	ATC	5,818,070			5,818,070
699432 PLS PR1 345 270941 ZION STA ; R 345 1	Rosecrans 345kV, New Substation	ATC	59,774,390			59,774,390
699432 PLS PR1 345 274817 ZION EC ;RP 345 1						
699939 SAL 138 138 699235 WAU 138 138 1	Sand Lake – Wautoma 138kV (X-11), rebuild	ATC	13,514,000			13,514,000

[redacted]

698313 SALT 69 69.0 698312 HAN 69 69.0 1	Sand Lake Tap – Hancock 69kV (Y-90), rebuild	ATC	4,902,000			4,902,000
693855 SILVER RIVER 138 699883 HUMBOLDT SWS 138 1	Silver River – Humboldt Tap 138 kV (NLKG31), uprate	ATC	580,378			580,378
698879 SGR CK4 138 699360 NLK GV T 138 1	Sugar Creek - North Lake Geneva Tap 138kV (6541), rebuild	ATC	15,970,000			15,970,000
699492 TOSA-W 138 693544 MILWKE CTY T 138 1	Tosa – Milwaukee County Tap 138kV (5041), rebuild	ATC	7,503,000			7,503,000
699512 UNVRSTY 138 698883 WHTWTR5 138 1	University-Whitewater 138kV (UNIG51), reconfigure and rebuild	ATC	4,876,439			4,876,439
699235 WAU 138 138 698286 WAU 69 69.0 1	Wautoma SS, 2nd 138/69kV transformer	ATC	5,108,064			5,108,064
699235 WAU 138 138 699234 RDR 138 138 1						
699939 SAL 138 138 89864 J986 POI 138 1						
694080 WERNER W B2 345 699359 N APPLETON 345 1	Werner West – North Appleton 345 kV (NAPL31), uprate	ATC	714,342			714,342
698883 WHTWTR5 138 699516 BLUFFCRK 138 1	Whitewater-Sugar Creek 138kV (WHIG53), rebuild	ATC	14,469,015			14,469,015
699429 BCR_LNG_TAP 138 699488 SGR CK5 138 1						
699516 BLUFFCRK 138 699429 BCR_LNG_TAP 138 1						
44137 J1413 POI 345 41814 J1181 POI 345 1	J1413 POI - J1181 POI 345kV, uprate	ITCM	15,000,000			15,000,000
44137 J1413 POI 345 41814 J1181 POI 345 1 C						
631144 MITCHLCO3 345 44137 J1413 POI 345 1	Mitchell County - J1413 POI 345kV, uprate	ITCM	1,000,000			1,000,000
631142 ARNOLD 3 345 72860 J1284 POI 345 1	Arnold- J1284 POI 345kV, uprate	ITCM	1,000,000			1,000,000
631139 HAZLTON3 345 631142 ARNOLD 3 345 1	Hazleton - Arnold 345 kV, Uprate	MEC	600,000			600,000
41814 J1181 POI 345 631139 HAZLTON3 345 1	J1181 POI - Hazleton 345kV, uprate	MEC / ITCM	21,500,000			21,500,000
41814 J1181 POI 345 631139 HAZLTON3 345 1 C						
601002 ADAMS 3 345 631144 MITCHLCO3 345 1	Adams – Mitchell County 345 kV, terminal uprate	XCEL	1,500,000			1,500,000

[redacted].

8.2 Network Upgrade Alternatives Considered

Most of ATC NRIS network upgrades identified in Table 8.1-2 are direct upgrades of the constraint facilities to ATC design standards and considered as least-cost solutions at this point. Alternatives will be considered in Phase 2 for the following Network Upgrades if they are still required in Phase 2.

- Elm Road – Mount Pleasant 345kV, New Line
- Rosecrans 345kV, New Substation
- New 345 kV switching station for 2222, PLPL81, L-ERG71
- Concord – Bark River 138 kV, New Line

9.0 COST ALLOCATION AND TRANSMISSION OWNER SELF-FUND ELECTION

The cost allocation of Network Upgrades for the study group reflects responsibilities for mitigating system impacts based on Interconnection Customer-elected level of Network Resource Interconnection service as of the System Impact Study report date. The cost estimate for each network upgrade was provided by the corresponding transmission owning company.

Per MISO tariff, Transmission Owners must provide a non-binding indication of whether or not they will self-fund any Network Upgrades identified in the System Impact Study analysis. The Self-Funding elections are shown in sections 9.1, 9.2, and 9.3.

9.1 Interconnection Facilities Proposed for DPP 2020 Cycle Phase 1 Projects

For DPP 2020 Cycle Phase 1 East (ATC) group, the total costs of interconnection facilities are summarized in Table 9.1-1.

Table 9.1-1 – Interconnection Facilities for DPP 2020 Cycle Phase 1 Projects

MISO Queue #	Interconnection Facilities ($)	
	TO Network Upgrades	Self-Fund
J1497	540,589	Yes
J1502	10,245,000	Yes
J1508	7,813,000	Yes
J1510	1,305,893	Yes
J1512	3,976,700	Yes
J1513	1,459,771	Yes
J1567	1,469,767	Yes
J1573	971,985	Yes
J1615	1,710,311	Yes
J1629	11,268,000	Yes
J1706	908,384	Yes
J1708	1,377,857	Yes
J1716	0	N/A

[redacted].

J1719	4,933,354	Yes
J1720	7,330,000	Yes
J1732	6,978,000	Yes
J1735	663,777	Yes
J1740	7,618,000	Yes
J1745	418,405	Yes
J1746	867,472	Yes
J1750	7,151,000	Yes
J1751	7,151,000	Yes
J1752	6,938,397	Yes
J1773	12,311,000	Yes
J1778	0	N/A
J1779	0	N/A
J1781	3,394,162	Yes
J1793	1,446,544	Yes
J1803	280,121	Yes
J1814	359,911	Yes
J1817	280,121	Yes
J1824	353,698	Yes
J1843	0	N/A

9.2 ERIS Network Upgrades Proposed for DPP 2020 Cycle Phase 1 Projects

Network upgrades for Energy Resource Interconnection Service (ERIS) were identified in the ERIS analysis. The ERIS network upgrades include thermal network upgrades and voltage support network upgrades identified in the steady-state analysis. For DPP 2020 Cycle Phase 1 East (ATC) group, the total costs of ERIS network upgrades for the 2025 scenario are summarized in Tables 9.2-1, 9.2-2, 9.2-3, 9.2-4, 9.2-5, 9.2-6 and 9.2-7.

Table 9.2-1 – ERIS Network Upgrades Identified in Steady State Analysis

Network Upgrade	Facility Owner	Cost Used for Cost Allocation ($)[1,2]	Self-Fund
7 Mile Creek - Port Edwards 138 kV (X-11), Rebuild	ATC	7,011,343	Yes
Sand Lake - Hancock 69 kV (Y-90), Uprate	ATC	1,430,384	Yes
Academy SS, Transformer Replacement	ATC	4,001,020	Yes
North Randolph - Green Lake 138 kV (X-30), Uprate	ATC	2,405,225	Yes
Kegonsa-Koshkonong 138 kV (G-CHR21), Uprate	ATC	1,095,926	Yes
North Monroe - J1305 POI 138 kV (X-12), Uprate	ATC	696,625	Yes

[redacted]

Bass Creek - J1305 POI 138 kV (X-12), Uprate	ATC	656,262	Yes
Darlington - North Monroe 138 kV (X-49), Uprate	ATC	481,688	Yes
South Monroe - Brown Town 69 kV (Y-155), Rebuild	ATC	10,175,216	Yes
Eden - Highland 138 kV (X-147), Rebuild	ATC	5,521,348	Yes
Highland - Spring Green 138 kV (X-17), Reconductor	ATC	7,333,800	Yes
Hill Valley - Eden 138 kV (X-127), Rebuild	ATC	2,584,001	Yes

[1] All Network Upgrades were estimated on the earliest ISD dollars of responsible generator.
[2] ATC Network Upgrades included a contingency based on a project risk generally between 5% – 20%.

Table 9.2-2 – ERIS Network Upgrades in Dynamic Stability Analysis

To be determined in MISO DPP 2020 Cycle Phase 2

Table 9.2-3 – ERIS Network Upgrades Identified in PSCAD Analysis

To be determined in MISO DPP 2020 Cycle Phase 2

Table 9.2-4 – ERIS Network Upgrades in Short Circuit Analysis

To be determined in MISO DPP 2020 Cycle Phase 2

Table 9.2-5 – ERIS Affected System Network Upgrades

To be determined in MISO DPP 2020 Cycle Phase 2

Table 9.2-6 – ERIS PJM Affected System Network Upgrades

To be determined in MISO DPP 2020 Cycle Phase 2

Table 9.2-7 – ERIS Shared Network Upgrades

Constraint	Facility Owner	Network Upgrade	Cost ($)
None	-	-	-

9.3 NRIS Network Upgrades Proposed for DPP 2020 Cycle Phase 1 Projects

Network upgrades for Network Resource Interconnection Service (NRIS) were identified in the MISO's deliverability analysis and listed in the Table 9.3-1 below.

Table 9.3-1 – NRIS Network Upgrades Identified

Network Upgrade	Network Upgrade Owner	Cost Used for Cost Allocation ($)[1,2]	Self-Fund
J1352 - J1363 345 kV, Rebuild	Ameren	3,000,000	Yes
J1363 - J1338 345 kV, Rebuild	Ameren	16,000,000	Yes
Montgomery - J1352 345 kV, Rebuild	Ameren	5,000,000	Yes
Spencer Creek - J1338 345 kV, Rebuild	Ameren	3,000,000	Yes
Bristol – Elkhorn 138 kV (X-81), uprate	ATC	422,537	Yes
Concord – Bark River 138 kV, New Line	ATC	34,353,926	Yes
Cypress – Arcadian 345 kV (L-CYP31), uprate	ATC	2,116,487	Yes
Darlington – Rock Branch 69 kV (Y-109), uprate	ATC	200,469	Yes
Elkhorn – North Lake Geneva 138 kV (X-55), uprate	ATC	650,218	Yes
Elm Road – Mount Pleasant 345kV, New Line	ATC	46,429,634	Yes
Granville – Arcadian 345 kV (9911), uprate	ATC	3,885,243	Yes
Granville SS, 345kV Ring Bus (MTEP PID: 16490 Target A in MTEP21)	ATC	No Cost Allocation	N/A
Granville-Butler 138kV (3453) and Granville-Tosa 138kV (3443), rebuild	ATC	22,843,826	Yes
J1305 POI – Bass Creek 138kV (X-12), reconductor	ATC	4,343,432	Yes
Mass – Bruce Crossing 69 kV (6530), uprate	ATC	5,548,071	Yes
New 345 kV switching station for 2222, PLPL81, L-ERG71	ATC	25,531,789	Yes
New Switching Station – Rosecrans 345 kV (PLPL81), uprate	ATC	3,515,109	Yes
North Lake Geneva Tap – Burlington 138kV (6541), rebuild	ATC	11,583,000	Yes
North Monroe SS, 138/69 kV transformer replacement	ATC	3,841,935	Yes
Paris SS, 2nd 345/138kV Transformer	ATC	8,598,800	Yes
Rock River – Townline Road 138 kV (X-74), uprate	ATC	391,848	Yes
Rocky Run – Werner West 345 kV (WERWL41), uprate	ATC	5,818,070	Yes
Rosecrans 345kV, New Substation	ATC	59,774,390	Yes
Sand Lake – Wautoma 138kV (X-11), rebuild	ATC	13,514,000	Yes
Sand Lake Tap – Hancock 69kV (Y-90), rebuild	ATC	4,902,000	Yes
Silver River – Humboldt Tap 138 kV (NLKG31), uprate	ATC	580,378	Yes
Sugar Creek - North Lake Geneva Tap 138kV (6541), rebuild	ATC	15,970,000	Yes
Tosa – Milwaukee County Tap 138kV (5041), rebuild	ATC	7,503,000	Yes
University-Whitewater 138kV (UNIG51), reconfigure and rebuild	ATC	4,876,439	Yes
Wautoma SS, 2nd 138/69kV transformer	ATC	5,108,064	Yes
Werner West – North Appleton 345 kV (NAPL31), uprate	ATC	714,342	Yes
Whitewater-Sugar Creek 138kV (WHIG53), rebuild	ATC	14,469,015	Yes
J1413 POI - J1181 POI 345kV, uprate	ITCM	15,000,000	Yes
Mitchell County - J1413 POI 345kV, uprate	ITCM	1,000,000	Yes
Arnold - J1284 POI 345kV, uprate	ITCM	1,000,000	Yes
Hazleton - Arnold 345 kV, Uprate	MEC	600,000	Yes

[redacted]

[redacted] [redacted].

J1181 POI - Hazleton 345kV, uprate	MEC / ITCM	21,500,000	Yes
Adams – Mitchell County 345 kV, terminal uprate	XCEL	1,500,000	Yes

[1] All Network Upgrades were estimated on the earliest ISD dollars of responsible generators.
[2] ATC Network Upgrades included a contingency based on a project risk generally between 5% – 20%.

9.4 Cost Allocation Methodology for Thermal Network Upgrades

The costs of Network Upgrades (NU) for a set of generation projects (one or more subgroups or entire group with identified NU) are based off the MW impact of the worst-case scenario for each specific generator project. Basically, whatever the highest MW impact (increasing flow) is for that particular generator where the constraint is identified and requires NU is how it should be calculated.

Constraints which are mitigated by one or a subset of NU are identified. The highest MW contribution on these constraints from each generating facility is calculated in the MISO DPP study models without any Network Upgrades. Then the cost of each NU is allocated based on the pro rata share of the MW contribution from each generating facility on the constraints mitigated or partly mitigated by this NU. The methodology to determine the cost allocation of NU is:

$$\text{Project A cost portion of NU} = \text{Cost of NU} \times \left(\frac{Max(Proj.A \text{ MW } contribution \text{ on constraint})}{\sum_i Max(Proj.i \text{ MW } contribution \text{ on constraint})} \right)$$

9.5 Cost Estimating and Allocation Methodology for Short Circuit Upgrades

For each ATC breaker shown to be overdutied a new breaker will be scoped and the cost of that upgrade will be assigned to generators. No breaker duty analysis is performed for Affected System equipment. Appendix N provides short circuit data for all substation buses 69 kV and above included in ATC protection CAPE models. Any non-ATC equipment requiring a change would be considered Affected System.

Once ATC breaker replacement costs are determined, they are allocated proportionally to study generators that have a greater than 3% of the total of all current queue study generator contributing fault currents under the single line-ground short circuit fault simulation at the identified substation.

The system impact study does not include any substation ground grid screening study. ATC conducts a ground grid evaluation for ATC brownfield substations in MISO DPP Facility Studies based on available ground grid design documents or in-house models when major substation work is identified. Major substation work includes, but is not limited to:

- Generation addition (brownfield POIs)
- Substation expansion
- Transmission line addition
- Transformer addition or replacement
- Protective device replacement for SLG short-circuit duty reasons

9.6 Cost Allocation Tables

The cost allocation of Network Upgrades for the study group reflects responsibilities for mitigating system impacts based on Interconnection Customer-elected level of Network Resource Interconnection service as of the issued date of the System Impact Study report.

Assuming all generating facilities in the DPP 2020 Cycle Phase 1 (East ATC) group advance, Table 9.6-1 - Table 9.6-6 show how the costs for ERIS steady-state Network Upgrades, stability Network Upgrades, EMT stability Network Upgrades, , short-circuit Network Upgrades and PJM affected system Network Upgrades allocated to responsible generating facilities.

Due to the queue size and a large number of study generators in different MISO regions that were identified to be responsible for the NRIS Network Upgrades, considering readability, the detailed NRIS Network Upgrade cost allocation information including worst MW impact and cost allocation percentage are provided in Appendix I.

Table 9.6-1 – ERIS Steady-State Thermal Network Upgrade Cost Allocation %

Required ERIS Network Upgrades	Cost Estimates ($)	Worst MW Impact									Cost Allocation %								
		J1512	J1629	J1719	J1720	J1751	J1773	J1781	J1824	J1843	J1512	J1629	J1719	J1720	J1751	J1773	J1781	J1824	J1843
J986 POI - Port Edwards 138 kV (X-11), Rebuild	7,011,343	-	-	48.21	6.40	6.59	-	-	4.09	-	-	-	73.83	9.8	10.1	-	-	6.27	-
Sand Lake - Hancock 69 kV (Y-90), Uprate	1,430,384	-	-	20.10	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-
Academy SS, Transformer Replacement	4,001,020	-	-	-	23.33	-	-	-	17.68	-	-	-	-	56.9	-	-	-	43.1	-
North Randolph - Green Lake 138 kV (X-30), Uprate	2,405,225	-	7.76	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-
Kegonsa-Koshkonong 138 kV (G-CHR21), Uprate	1,095,926	-	-	-	-	-	-	-	-	1.60	-	-	-	-	-	-	-	-	100
North Monroe - J1305 POI 138 kV (X-12), Uprate	696,625	33.57	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-
Bass Creek - J1305 POI 138 kV (X-12), Uprate	656,262	33.57	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-
Darlington - North Monroe 138 kV (X-49), Uprate	481,688	36.74	-	-	-	-	9.38	9.38	-	-	66.2	-	-	-	-	16.9	16.9	-	-
South Monroe - Brown Town 69 kV (Y-155), Rebuild	10,175,216	13.52	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-
Eden - Highland 138 kV (X-147), Rebuild	5,521,348	-	-	-	-	-	36.42	36.42	-	-	-	-	-	-	-	50	50	-	-
Highland - Spring Green 138 kV (X-17), Reconductor	7,333,800	-	-	-	-	-	28.95	-	-	-	-	-	-	-	-	100	-	-	-
Hill Valley - Eden 138 kV (X-127), Rebuild	2,584,001	-	-	-	-	-	47.22	47.22	-	-	-	-	-	-	-	50	50	-	-

Table 9.6-2 – ERIS Steady-State Thermal Network Upgrade Costs Allocated to Each Generation Project

Required ERIS Network Upgrades	Cost Estimates ($)	Cost Allocation ($)								
		J1512	J1629	J1719	J1720	J1751	J1773	J1781	J1824	J1843
J986 POI - Port Edwards 138 kV (X-11), Rebuild	7,011,343	-	-	5,176,475	687,112	708,146	-	-	439,611	-
Sand Lake - Hancock 69 kV (Y-90), Uprate	1,430,384	-	-	1,430,384	-	-	-	-	-	-
Academy SS, Transformer Replacement	4,001,020	-	-	-	2,276,580	-	-	-	1,724,440	-
North Randolph - Green Lake 138 kV (X-30), Uprate	2,405,225	-	2,405,225	-	-	-	-	-	-	-
Kegonsa-Koshkonong 138 kV (G-CHR21), Uprate	1,095,926	-	-	-	-	-	-	-	-	1,095,926
North Monroe - J1305 POI 138 kV (X-12), Uprate	696,625	696,625	-	-	-	-	-	-	-	-
Bass Creek - J1305 POI 138 kV (X-12), Uprate	656,262	656,262	-	-	-	-	-	-	-	-
Darlington - North Monroe 138 kV (X-49), Uprate	481,688	318,877	-	-	-	-	81,405	81,405	-	-
South Monroe - Brown Town 69 kV (Y-155), Rebuild	10,175,216	10,175,216	-	-	-	-	-	-	-	-
Eden - Highland 138 kV (X-147), Rebuild	5,521,348	-	-	-	-	-	2,760,674	2,760,674	-	-
Highland - Spring Green 138 kV (X-17), Reconductor	7,333,800	-	-	-	-	-	7,333,800	-	-	-
Hill Valley - Eden 138 kV (X-127), Rebuild	2,584,001	-	-	-	-	-	1,292,000	1,292,000	-	-
Total ERIS Steady State Thermal Network Upgrade Cost ($) Allocated To Each Generator		**11,846,981**	**2,405,225**	**6,606,859**	**2,963,692**	**708,146**	**11,467,880**	**4,134,080**	**2,164,051**	**1,095,926**

[redacted]

Table 9.6-3 – ERIS Stability Network Upgrade Costs Allocated to Each Generation Project

To be determined in MISO DPP 2020 Cycle Phase 2.

Table 9.6-4 – ERIS EMT Stability Network Upgrade Costs Allocated to Each Generation Project

To be determined in MISO DPP 2020 Cycle Phase 2.

Table 9.6-5 – ERIS Short-Circuit Network Upgrade Costs Allocated to Each Generation Project

To be determined in MISO DPP 2020 Cycle Phase 2.

Table 9.6-6 – PJM Affected System Costs Allocated to Each Generation Project

To be determined in MISO DPP 2020 Cycle Phase 2.

[redacted]

10.0 AVAILABLE APPENDIX DOCUMENTS (NOT ATTACHED)

Appendix A – Study Criteria, Methodology, and Assumptions

Appendix B – ATC Planning Criteria and Generation Facility Interconnection Guide

Appendix C – Interconnection Facility Project Diagrams and Modeling Details

Appendix D – Network Upgrade Project Diagrams
Note: Project Diagrams were not developed for line uprate projects.

Appendix E – Steady State Power Flow Results

Appendix I – MISO Deliverability Study Results

Appendix J – Assessed System Performance Reference

Appendix K – J1502 Additional Studies